THEORY AND PRACTICE OF ELECTRICITY PRICING IN THE UNITED STATES

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THESIS

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ABSTRACT

This paper is a study of the current state of the art, in both the theory and actual practice, of electricity pricing in the United States under capacity and revenue constraints. It is also an attempt to derive an efficient pricing policy that will be applied to large Government installations. A mathematical formulation of electricity pricing using two different approaches is presented.

Components of the total cost of service are examined along with various methods of allocating them among classes of customers. Also discussed are difficulties in allocating capacity costs due to the existence of joint costs. Commonly used methods of allocating capacity costs are presented along with a discussion of the merits of each. Finally, this paper explores the impact of electricity generation upon the environment, especially thermal and air pollution, and methods of controlling each type of pollution in the context of overall pricing are discussed.

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I. INTRODUCTION

Essentially, the electric utility business is the same as any other privately owned enterprise. The utility gets its capital in the competitive money market and therefore it must make a margin over operating expenses to stay in business. There are, however, three important differences between the electric utility and the usual business enterprise. First, the utility has an obligation to serve all who apply for service. Second, the utility does not have direct competition; that is, only one utility operates in an area, except in isolated instances. Third, in place of direct competition, government regulation is substituted. The first of these requires that the utility is always in a state of readiness, that is, ready to anticipate a sudden increase in capacity or energy demands. Thus, the electric utility should be looked upon as a normal business enterprise with the added element of regulation.

One of the principle objectives of State regulation is, of course, to limit the earnings of the utilities to a "fair" return on the true value of the property. Of equal importance is the quality of service rendered by the utility, such as, continuity of service, frequency control and voltage regulation. The deterioration of the quality of electrical service would itself and through its economic repercussion degrade the national life. What then becomes a

major issue is the manner in which the rates of the utility service should be determined in the absence of normative definition of "fair return". Further complications arise as a result of significant variations in the demands not only over the months and the year, but also on a weekly and daily basis.

This thesis is an attempt to establish a picture of the underlying theory concerning utility service pricing along with the actual practices by the utility enterprises. Along the way we highlight the difficulties faced by the utility enterprise in following both the marginal cost pricing principle and state regulations. Increasing returns and technical characteristics of the system are the cause of the former, while vagueness is the reason for the latter.

Section II develops the mathematical formulation of electricity pricing under capacity and revenue constraints, which leads to the conclusion that price is, in general, not equal to marginal cost. In particular, this section deals with the problem of variable demands for the utility services.

Section III discusses the total cost of service and all the cost components that go into it. Here, the difficulties in measuring the marginal cost and the vagueness of the State regulation are presented. The main concern of this section is to show that in practice the amount of allowable revenue is predetermined by the Commission before the rate is set-up, thus forcing the utility to deduce what appropriate

rates will produce that revenue, instead of, what rates are "fair" to the consumers.

Section IV describes the apportionment of the total cost of service into three cost categories, that is, customer costs, demand costs and energy costs. The allocation of each category into classes of service is also discussed. As a result of the attempt to fully allocate the total cost of service, we will find in this section that the customer costs category becomes the "dumping place" for all un-allocated costs.

In Section V, various rate forms are discussed together with its rules and provisions. It is common practice to "block" the rate of a tariff to induce higher consumption at a reduced price. Further sales promotion efforts are embodied in the provisions of the tariff. Thus, the tariff of the utility services can be looked upon as the actual pricing practices by the enterprise.

Section VI deals with the effects of electric generation upon its environment. It was only recently that the public became acutely aware that clean air is an important natural resource, and demanded a reduction in emissions to the atmosphere, even though such demand may result in increased prices for services. Also, the waste heat, discharged to bodies of water by the power plants, has become the target of the environmentalists as well as State and Federal Commissions. The prime interest of this section is to show that the incremental cost of pollution control over the

operating cost prior to the installation of the pollution devices is very small and therefore no additional charge to the customer is necessary.

The last section is the conclusion of this thesis along with a suggestion of areas for further study.

Finally, as a reflection for the difficulties in setting-up a fair rate, we quote the words of Prof. James.C. Bonbright: "The art of rate making is an art of wise compromise" which is ironically true.

II. THE VARIABLE LOAD PROBLEM

A. STATEMENT OF THE PROBLEM

A public utility company usually operates under two major constraints, i.e., capacity and return from operations. The latter gives rise to the departure of price from marginal cost as shown independently by Steiner [31], Williamson [38] and others [24, 27]. Furthermore, it also dictates how far the price is allowed to deviate from the marginal cost so that the net return from operations does not violate the standard of "fair return" set by the Government and yet enough to cover all expenses.

The basic questions each company faces are: What rates charged to consumers may be judged reasonable or fair? What are the appropriate concepts or standards of reasonableness or fairness?

The answers to those questions depend upon the local conditions and the approach that one used. One of the approaches that is mathematically tractable is that of value-of-service which gives recognition to the demand side of the market. The value derives primarily from the fact that they can satisfy consumer's needs and wants so effectively that consumers are willing to pay a price to acquire them.

One definition of the value of service that lends itself more readily to reasonable quantification - and hence to

mathematical tractability - uses the economic notion of consumer's surplus concept; that is, the difference between what a consumer would be willing to pay for a service and what he actually pays. Thus, from the consumer's point of view, the consumer's surplus is a measure of net benefit he derives from buying a certain quantity of good or service. If we consider the benefit to both the consumer and the producer, then the total gross benefit will be defined as the consumer's surplus plus the total revenue. The net benefit, therefore, can be defined as the gross benefit minus the total cost.

Hence, by maximizing the net benefit enjoyed both by the consumer and the producer, the reasonableness of the price of the utility services can be achieved and at the same time enough return for the company can be guaranteed so that its obligations to the stockholders can be met.

As a result, the goal of the utility company can be formulated as follows:

maximize (net benefit)

which is equivalent to:

max. (gross benefit - total cost)

which is equivalent to

max. (consumer's surplus + total revenue - total cost)

This is the objective function which represents the utility company's goal. The constraints are:

profit $\leq$ some predetermined value

and

capacity demanded $\leq$ maximum capacity of the utility.

B. FORMULATION OF THE OBJECTIVE FUNCTION

Let P* be the equilibrium price that the consumer actually pays for the equilibrium quantity q* (Fig. 1). For each quantity q, $0 < q < q^*$, the consumer would be willing to pay an excess price $P(q) > P^*$ rather than go without it entirely. Thus buying q* units at price P* the consumer accumulates some satisfaction in the form of excess price. This satisfaction has been designated the consumer's surplus. Denoting consumer's surplus by S, this surplus becomes

$$S = \int_0^{q^*} \{P(q) - P^*\}dq = \int_0^{q^*} P(q)dq - P^*q^* \qquad (1)$$

where the first term on the right hand side is the gross benefit and the second term is the total revenue derived from the sale of q*. Assume that the demand for the i^{th} good is independent of any other good, then each good will yield a surplus of the form of Equation (1), i.e.:

$$S_i = \int_0^{q^*} P_i(q_i)dq_i - P_i^* q_i^* \qquad (2)$$

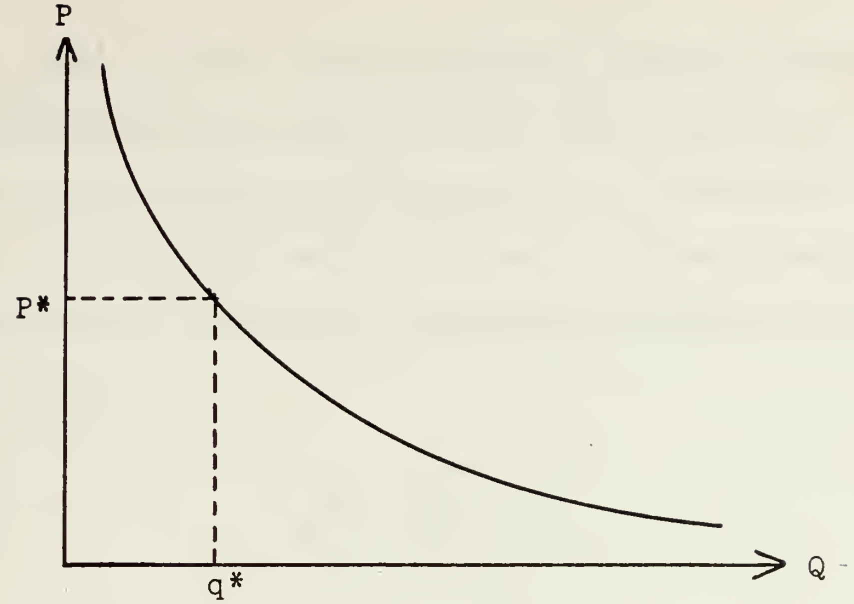


FIGURE 1.

And the total consumer's surplus is given by:

$$S = \sum_{i=1}^{n} S_i = \sum_{i=1}^{n} \int_0^{q_i^*} P_i(q_i)dq_i - \sum_{i=1}^{n} P_i^* q_i^* \quad (3)$$

An extension of Equation (3) was given by Steiner [31] who allowed demand for different goods to be interdependent. The gross benefit for each good was represented by:

$$F_i = \int_{q_i} P_i dq_i \quad (4)$$

where $P_i = P_i(q_1, q_2, \ldots, q_i, \ldots, q_n)$. The total gross benefit would then be:

$$\sum_{i=1}^{n} F_i = \sum_{i=1}^{n} \int_{q_i} P_i dq_i \quad (5)$$

As a result of the inter-dependency between demands, cross elasticity exists, which implies that the value of the integral in (5) depends upon the path of integration and therefore the objective will not have a unique first derivative. Therefore the following integrability condition must be satisfied, i.e.:

$$\frac{\partial P_i}{\partial q_j} = \frac{\partial P_j}{\partial q_i}$$

the economic meaning of which is that there be no income effect between those goods [30].

Now, since the demand for electricity can be classified as occurring either during the peak or the off-peak period, they can be considered as two different goods offered at different times. Therefore, for our convenience, the consumer's surplus in the demand of electricity is defined as:

$$S = \Sigma_i S_i = \Sigma_i \int_{0,0}^{q_1^*, q_2^*} P_i dq_i - \Sigma_i P_i^* q_i^* \; ; \; i=1,2 \tag{6}$$

and the net benefit is:

$$\text{net benefit} = \Sigma_i \int_{0,0}^{q_1^*, q_2^*} P_i dq_i - C(q_i^*, q_2^*, K);$$

$$i = 1,2 \tag{7}$$

where, $C(q_1,q_2,K)$ is the total cost incurred by the company. The first constraint is that profit does not exceed the predetermined amount or:

$$\Sigma_i P_i q_i - C(q_1,q_2,K) \leq M \; ; \quad i = 1,2 \tag{8}$$

The second constraint is the capacity constraint; that is demand in each period does not exceed maximum capacity or:

$$q_i \leq K \; ; \quad i = 1,2 \tag{9}$$

The cost function $C(q_1,q_2,K)$ consists of two parts, i.e., the variable cost in each period and the fixed cost of establishing a utility of capacity K, or

$$C(q_1,q_2,K) = D_1(q_1,K) + D_2(q_2,K) + \bar{q}(K) \tag{10}$$

If the variable cost functions are linear functions of q and the fixed cost is a linear function of K, then (10) becomes,

$$C(q_1,q_2,K) = bq_1 + bq_2 + \beta K \tag{11}$$

where b is the operating cost per unit per period and β is the cost per unit of capacity.

C. THE INDEPENDENT DEMAND MODEL

Reformulation of what has been described in the preceeding paragraph is as follows:

$$\max \int \sum_{i=1}^{2} P_i dq_i - C(q_1,q_2,K) \qquad (12)$$

$$\text{s.t.} \quad \sum_{i=1}^{2} P_i q_i - C(q_1,q_2,K) \leq M.$$

$$q_i \leq K \qquad i = 1,2$$

$$q_i \leq 0, \quad K \geq 0 \qquad i = 1,2$$

where $P_i = P_i(q_1,q_2)$ and the total cost function is that given by Equation (10). The Lagrangian of the above problem is

$$\int \sum_{i=1}^{2} P_i dq_i - C(q_1,q_2,K) + \lambda[\sum_{i=1}^{2} P_i q_i - C(q_1,q_2,K) - M]$$
$$- \sum_{i=1}^{2} \gamma_i (q_i - K) \qquad (13)$$

Thus on applying the Kuhn-Tucker conditions for the maximization problem yields

$$(1 + \lambda)(P_i - \frac{\partial C}{\partial q_i}) + \lambda \sum_{j=1}^{2} q_j \frac{\partial P_j}{\partial q_i} - \gamma_i \leq 0 \tag{14}$$

$$(\sum_{i=1}^{2} \gamma_i) - (1 + \lambda) \frac{\partial C}{\partial K} \leq 0 \tag{15}$$

$$q_i - K \leq 0 \tag{16}$$

$$\sum_{i=1}^{2} P_i q_i - C - M \leq 0 \tag{17}$$

When demand is assumed independent, $P_1 = P_1(q_1)$ and $P_2 = P_2(q_2)$, several important cases are:

a) $\lambda = 0$ and $\gamma_i = 0 \quad i = 1,2$

We will get,

$$P_1(q_1) = \frac{\partial D_1}{\partial q_1} \tag{18}$$

$$P_2(q_2) = \frac{\partial D_2}{\partial q_2} \tag{19}$$

which says that price is equal to the marginal cost. Also we get,

$$\frac{\partial C}{\partial K} = \frac{\partial D_1}{\partial K} + \frac{\partial D_2}{\partial K} + \frac{\partial \bar{q}}{\partial K} = 0 \tag{20}$$

which says that the marginal cost increase in expanding the utility capacity by one unit is offset by a marginal cost decrease in operation costs, which is similar to that

obtained by Mohring [24]. Observe also that (20) means that the capcity of the utility is at an optimum.

b) $\lambda = -1$ and $\gamma_i = 0 \quad i = 1,2.$

This occurs as a solution of (15) whenever (20) does not hold. We get

$$-q_1 \frac{dP_1}{dq_1} = 0 \quad \text{and} \quad -q_2 \frac{dP_2}{dq_2} = 0$$

or

$$P_i \frac{q_i}{P_i} \frac{dP_i}{dq_i} = 0$$

or

$$\frac{P_i}{\varepsilon_i} = 0 \tag{21}$$

where $\varepsilon_i = - \frac{P_i}{q_i} \frac{\partial q_i}{\partial P_i}$ is the demand elasticity of price. Equation (21) tells us either $P_i = 0$ or $\varepsilon_i = \infty$ which implies that price is already set by the market.

c) $\lambda < 0, \quad \lambda \neq -1$ and $\gamma_i = 0 \quad i = 1,2.$

Equation (14) becomes

$$P_i(q_i) = \frac{\partial D_i}{\partial q_i} + \left(\frac{\lambda}{1 + \lambda}\right) \frac{1}{\varepsilon_i} P_i(q_i) \tag{22}$$

Notice that if $-1 < \lambda < 0$, the second term of the right hand

side in Equation (22) is < 0, because $\varepsilon_i > 0$ and therefore price is less than marginal operating cost. But since the production of electricity shows an increasing return, price less than marginal cost, even without capacity constraint, is unacceptable because total revenue will not recover total cost incurred. In other words, marginal cost can be looked upon as the lower bound of price. This leads Alfred Kahn [21] to conclude that the starting point for economically efficient pricing is the marginal cost.

D. THE DEPENDENT DEMAND MODEL

The demand functions are $P_i = P_i(q_1,q_2)$ and as before, several cases will be considered, i.e.:

a) $\lambda = 0$ and $\gamma_i = 0 \quad i = 1,2.$

The result will be similar to that given by Equations (18), (19) and (20).

b) $\lambda = 0$ and $\gamma_1 > 0, \quad \gamma_2 = 0.$

Here the capacity constraint is active during the first period and the Kuhn-Tucker conditions of Equations (14) through (17) yield,

$$P_1(q_1,q_2) = \frac{\partial D_1}{\partial q_1} + [\frac{\partial D_1}{\partial K} + \frac{\partial D_2}{\partial K} + \frac{\partial \bar{q}}{\partial K}] \tag{23}$$

$$P_2(q_1,q_2) = \frac{\partial D_2}{\partial q_2} \tag{24}$$

$$\gamma_1 = \frac{\partial C}{\partial K} = \frac{\partial D_1}{\partial K} + \frac{\partial D_2}{\partial K} + \frac{\partial \bar{q}}{\partial K} \tag{25}$$

$$q_1 = K \quad \text{and} \quad q_2 < K \tag{26}$$

Observe that demand during peak periods will bear the marginal operating cost plus the marginal capacity cost, while demand during off peak periods will bear only the marginal operating cost.

e) $\lambda = -1$ and $\gamma_1 > 0$, $\gamma_2 = 0$

Equations (14) through (16) will yield,

$$q_1 \frac{\partial P_1}{\partial q_1} = - q_2 \frac{\partial P_2}{\partial q_1} \tag{27}$$

$$q_2 \frac{\partial P_2}{\partial q_2} = - q_1 \frac{\partial P_1}{\partial q_2} \tag{28}$$

Since we have assumed that $\frac{\partial P_i}{\partial q_j} = \frac{\partial P_j}{\partial q_i}$, both equations above give

$$- \frac{1}{\varepsilon_1} = \frac{1}{\varepsilon_{21}} \quad \text{and} \quad - \frac{1}{\varepsilon_2} = \frac{1}{\varepsilon_{12}} \tag{29}$$

f) $\lambda < 0$, $\lambda \neq -1$ and $\gamma_1 > 0$, $\gamma_2 = 0$.

Equations (14) through (17) will yield

$$P_1(q_1,q_2) = \frac{\partial D_1}{\partial q_1} + \frac{\lambda}{1 + \lambda}\left[\frac{1}{\varepsilon_1} + \frac{1}{\varepsilon_{21}}\right]P_1(q_1,q_2) + \frac{\gamma_1}{1 + \lambda} \tag{30}$$

$$P_2(q_1,q_2) = \frac{\partial D_2}{\partial q_2} + \frac{\lambda}{1 + \lambda}\left[\frac{1}{\varepsilon_2} + \frac{1}{\varepsilon_{12}}\right]P_2(q_1,q_2) \tag{31}$$

$$\gamma_1 = (1 + \lambda)\left[\frac{\partial D_1}{\partial K} + \frac{\partial D_2}{\partial K} + \frac{\partial \overline{q}}{\partial K}\right] \tag{32}$$

$$P_1q_1 + P_2q_2 - D_1(q_1,K) - D_2(q_2,K) - \overline{q}(K) = M \tag{33}$$

and $q_1 = K$; $q_2 < K$.

Note that Equation (25) or (32) gives the optimum size of the utility.

E. LINEAR COST FUNCTION WITH DEPENDENT DEMAND

For the linear case, the total cost function will take the form of: $C(q_1,q_2,K) = bq_1 + bq_2 + \beta K$ where b is the unit operating cost per period; and β is the cost of providing a unit of capacity.

a) $\lambda = 0$ and $\gamma_1 > 0$, $\gamma_2 = 0$.

Equations (23) through (26) will yield

$$P_1(q_1,q_2) = b + \gamma_1 \tag{34}$$

$$P_2(q_1,q_2) = b \tag{35}$$

$$\gamma_1 = \beta \tag{36}$$

b) $\lambda < 0, \quad \lambda \neq -1$ and $\gamma_1 > 0, \quad \gamma_2 = 0.$

From (30) through (33) we will get

$$P_1(q_1,q_2) = b + \frac{\lambda}{1 + \lambda}\left[\frac{1}{\varepsilon_1} + \frac{1}{\varepsilon_{21}}\right]P_1(q_1,q_2) + \frac{\gamma_1}{1 + \lambda} \tag{37}$$

$$P_2(q_1,q_2) = b + \frac{\lambda}{1 + \lambda}\left[\frac{1}{\varepsilon_2} + \frac{1}{\varepsilon_{12}}\right]P_2(q_1,q_2) \tag{38}$$

$$\gamma_1 = (1 + \lambda)\beta \tag{39}$$

$$P_1q_1 + P_2q_2 - bK - bq_2 - \beta K = M \tag{40}$$

$$\text{and} \quad q_1 = K \; ; \qquad q_2 < K \tag{41}$$

F. A SOLUTION MODEL USING CONSUMER'S UTILITY FUNCTION

Mohring [24] saw the variable-load demand problem as a resource allocation problem facing the economy. Without having to make it too complicated, he assumed that the demand for utility services consists of two parts, i.e. the peak-period demand which he called X_1 and off-peak demand X_2.

Furthermore he assumed a third goal, the demand of which is X_3. Similar to that of Williamson, the cost function was treated in terms of the cycle-period outputs. Thus let α_i $(i = 1,2)$ denote the fraction of time the demand is of type i, and since the output is X_i if the whole cycle had been used to produce good i only then X_i/α_i would have actually been produced at a cost $C(X_i/\alpha_i, K)$, where K is the annual cost of the public utility's capital plant, therefore the operating cost of producing X_i is $\alpha_i C(X_i/\alpha_i, K)$.

Let $U^i(x_1^{\,i}, x_2^{\,i}, x_3^{\,i})$ be the individual utility function, and $(r^i - h^i)$ is his income.

Then the consumer behavior can be represented by:

$$\max \quad U^i(x_1^{\,i}, x_2^{\,i}, x_3^{\,i}) \tag{42}$$

$$\text{s.t.} \quad r^i - h^i = P_1 x_1^{\,i} + P_2 x_2^{\,i} + P_3 x_3^{\,i}$$

where r^i is the individual labour resources, h^i is his head tax, and P_j is unit price of the respective $x_j^{\,i}$. The public utility objective is:

$$\max \quad W(U^1, U^2, \ldots, U^n) \tag{43}$$

$$\text{s.t.} \quad R = \alpha_1 C_1 + \alpha_2 C_2 + x_3 + K$$

$$R = \sum_{i=1}^{n} r^i$$

$$C_i = C(X_i/\alpha_i, K) \quad , \quad i = 1,2$$

$$X_j = \sum_{i=1}^{n} x_j^i \quad , \quad j = 1,2,3$$

where W is the individualistic social welfare function.

Let Z be the Lagrangian of (43); its derivative with respect to K is

$$\frac{\partial Z}{\partial K} = - \lambda(\alpha_1 \frac{\partial C_1}{\partial K} + \alpha_2 \frac{\partial C_2}{\partial K} + 1) = 0 \tag{44}$$

which gives us the optimum capacity similar to that of Equation (20) derived in Paragraph (C).

Upon differentiation of Equation (43) with respect to P_1, P_2 and the I head taxes and then making the appropriate substitution, we get:

$$\begin{bmatrix} S_{11} & S_{21} \\ S_{12} & S_{22} \end{bmatrix} \begin{bmatrix} P_1 - C_{11} \\ P_2 - C_{22} \end{bmatrix} = \begin{bmatrix} 0 \\ 0 \end{bmatrix} \tag{45}$$

where $S_{jk} = \sum_i (x_{jk}^i - x_k^i \, x_{jh}^i)$, the sum of Hicks-Slutsky

pure substitution effect, and $x_{jk}^{\,i} = \partial x_j^{\,i}/\partial P_K$. Since the matrix $|S| = [S_{11}\,S_{22} - S_{12}\,S_{21}]$ is invertible, therefore it can be concluded that if no budget constraint exists, the utility should operate at the point where price and marginal cost (C_{11} or C_{22}) are equal.

If, however, a budget constraint of the form $\mu[P_1x_1 + P_2x_2 + D - \alpha_1C_1 - \alpha_2C_2 - K]$ is imposed to the problem (43), then again following the steps as above we get

$$\begin{bmatrix} S_{11} & S_{21} \\ S_{12} & S_{22} \end{bmatrix} \begin{bmatrix} C_{11} - P_1 \\ C_{22} - P_2 \end{bmatrix} = \frac{\mu}{\lambda + \mu} \begin{bmatrix} x_1 \\ x_2 \end{bmatrix} \qquad (46)$$

Since both S_{11} and S_{22} are negative while $|S| > 0$, therefore, if the utility service in peak and off-peak periods are substitutes, $S_{12}(=S_{21})$ will have a positive value and hence optimization subject to budget constraint requires that a price greater than marginal cost be charged in both periods. On the other hand, if the services in both periods are complements, a price below marginal cost should be charged during the off-peak period.

For the case when it is not possible to price differently for the services in both periods, a single price constraint is introduced, and the resulting price,

$$P = \frac{(S_{13}C_{11} + S_{23}C_{22})}{S_{13} + S_{23}}$$

is a combination of the marginal costs in both periods.

In all three cases mentioned above, the optimum capacity level would lead to the saving in the variable cost due to an increase in capacity because the increase in capacity cost is exactly offset by a decrease in variable cost, as for example, portrayed by Equation (44).

Thus, by using consumer's surplus concept for the public utility enterprise's objective function, Pressmann has been able to derive results which are of the form given us by Mohring. From (20) and (25) it is interesting to note that when no capacity constraint exists; i.e. $\frac{\partial C}{\partial K} = 0$, then capacity should be increased to the optimum value when the saving in operating marginal cost, i.e., $(\frac{\partial D_1}{\partial K} + \frac{\partial D_2}{\partial K})$, is just offset by the extra cost of acquiring new capacity. The situation is relevant to the decision of expanding the capacity by using new plant and thus obtaining lower operating cost. Following Williamson [38], if demand is such that $b + \gamma_1 > b + \beta$ and expected to remain at this level, then an expansion is called for. While if $b + \gamma_1 < b + \beta$ plant should be retired.

In models with only capacity constraint and no profit constraint prices are charged according to the marginal cost pricing principle. The peak period is charged the full marginal cost of capacity, while the off-peak period is charged the short run marginal cost. If, however, full capacity is utilized in both periods, then each period shares the marginal capacity cost and the period with the

greater actual demand gets charged the larger share. This is the principle appied by Houtakker to both peak and potential peak period in his three periods scheme.

With the introduction of a profit constraint, the prices depend on both the marginal cost and the elasticites of demand which unquestionably leads to the departure from the marginal cost pricing principle. Jefferson [20] went even further and specified that rates should be designed closer to marginal cost for services which have elastic demand and further away from the marginal cost for service which have inelastic demand. This proposition, of course, a consequence of Equation (37) either for a dependent demand or independent demand model. Because the deviation from the marginal cost contains a component which is proportional to $(\frac{1}{\varepsilon_i} + \frac{1}{\varepsilon_{ij}})$, if we are willing to assume that cross elasticity does not exist, i.e., no $\frac{1}{\varepsilon_{ij}}$ term, then the more inelastic the demand the larger is the deviating component imposed by the profit constraint. It may be that this is not a desirable policy to be applied to the lowest income group customers because, for example according to Berman et al [8], they show an elasticity of -0.25 (with gas cross elasticity of +0.08).

Although the results presented in this section were derived using consumer's surplus concept, they are similar to that derived by Mohring [24] using utility concept and also to that derived by Marcus Fleming [15]. They have in common that in general price is not equal to the marginal cost whenever the utility has to operate under profit and

and capacity constraints. However, it becomes apparent that the marginal cost is the starting point whence price will be determined. The amount of adjustment away from the marginal cost is determined by, among other things, the price elasticity of demand, consumer income and financial obligations to the stockholders. Whatever concept is used, in the final analysis, the main obstacle is the determination of the marginal cost itself. The difficulty in the assessment of the marginal cost is due to the time element that enters into the total cost.

III. THE COST STRUCTURE

A. COST CATEGORIES

The cost of electrical energy may be divided into the following categories: a) fixed element; b) energy element; c) customer element; and d) profit element. The first of these is governed by the extent of plant investment and the current financial rates. It remains a fixed sum regardless of the amount of energy sold. The second is directly proportional to the plant output. The customer element will be proportional to the number of customers and nearly independent of both the plant investment and its kilowatt-hour production. The profit is that amount of return allowed under the most recent regulation.

The sum of all cost elements of the utility is called cost-of-service which consists of the following four functional categories: a) operating cost; b) depreciation charges; c) taxes; and d) a "fair" return on the net valuation of the assets devoted to public service. Therefore the revenue has to be able to cover the cost-of-service; or in more compact form:

$$R = E + d + T + (V - D)r \qquad (47)$$

where:

R = revenue requirement

E = operating expenses

d = depreciation charges (D = accumulated depreciation)

T = taxes

V = gross valuation of the assets serving the public

r = rate of return

$(V - D)r$ = allowable net return ($V - D$ is called the rate base). Equation (47) is called the rate making formula, the validity of which is obvious. However, in practice, the fairness in the determination of each component of the above equation is open to questions. Among the most controversial is the determination of the last component.

B. OPERATING COST

Operating cost consists of the following major functional parts, i.e., a) generating cost; b) bulk transmission costs; c) distribution cost; d) metering and control system cost; e) customer's account activity and related matters; f) sales promotion; and g) general administrative cost.

1. Generating Cost

The generating cost is the cost of producing electric energy inside a plant or plants. For a thermal generating plant, the primary component of the generating cost is fuel cost. In addition to fuel cost, maintenance cost and labor cost are usually included. However, since labor is required

mainly to control rather than to operate a highly mechanized facility, the basic input of labor is sufficient for a wide range of operating output. It, therefore, may be assumed that incremental labor costs are non-existent or extremely low.

When generators are operated at higher capacities, greater wear is to be expected. Despite maintenance procedures, it is logical to assume that maintenance costs increase with output. However, a finding by the Federal Power Commission in 1970 as quoted by Sylvain Davis [13] shows the opposite. The results are as follows:

TABLE 1

Average operation and maintenance costs in the U.S. Fossil-fueled plants (in mills/kwh).

Year	Net generation in billion KWH	Operation	Maintenance	Total
1956	446.0	.48	.39	.87
1960	556.5	.47	.38	.85
1965	796.9	.38	.37	.75
1968	1026.7	.37	.38	.75

From this data it is apparent that operating cost and total cost are strongly related to net generation. Maintenance cost did not vary. The decreasing operation (generation) costs with increasing capacity support the theoretical prediction given us by Equation (20). Thus,

the real variable part of the generating costs is that of fuel. But according to Da Silva [39] it is a common practice of utility companies to assign maintenance cost as a variable cost, and worse yet, the incremental maintenance costs are set as a fixed percentage of the incremental fuel costs. Note that in a hydraulic generating plant incremental fuel costs are non-existent since the plant depends only on the water-level of the reservoir. In the U.S., where the main source of electric energy comes from thermal plants, it is common that whenever variable costs are mentioned it will always refer to thermal plants. In a system which consists of both types of generating plants, one could never be sure how the company determined its incremental variable cost (in the case of PG and E, 30% of its net output comes from hydro plants).

An empirical determination of incremental fuel cost in a thermal plant was introduced by Da Silva [14] using an aggregation technique of the individual generator units. An example of his result is presented in Table (2). The data was obtained by setting the generators to operate at various outputs and then measuring the thermal (BTU) input required to maintain the output. The required BTU were then converted to fuel requirements and finally to fuel costs. The data was then arranged to reflect the incremental fuel cost for the whole range of plant capacity (Table 3). Thus, for a utility system consisting of many plants, the procedure can be repeated for each plant thus establishing the necessary

TABLE 2

Incremental Fuel Cost by Generating Units

Unit or units #	Maximum Capacity (MW)	Output Range (MW)	Incremental Fuel Cost (mills/KWH)
1	90	0 - 35	3.06
		35 - 90	3.47
2	98	0 - 40	2.78
		40 - 75	3.09
		78 - 90	3.66
3	102	0 - 65	2.55
		65 - 102	2.96
4	102	0 - 65	2.71
		65 - 102	3.12
5,6	210	0 - 110	2.45
		110 - 210	2.84
7,8	102	0 - 65	2.58
		65 - 102	3.00
9.10	205	0 - 110	2.47
		110 - 210	2.87
11,12	95	0 - 35	3.18
		35 - 75	3.65
		75 - 95	4.60
13	90	0 - 55	3.04
		55 - 90	3.68
14	102	0 - 65	2.80
		65 - 102	3.31
15,16,17,18	102	0 - 65	2.86
		65 - 102	3.27

TABLE 3

Cumulative Capacity in Order of Incremental Fuel Cost

Unit #	Max Output (MW)	Cumulative Output	Incremental Fuel Cost (mills/KWH)
5	110	110	2.45
6	110	220	2.45
9	110	330	2.47
10	110	440	2.47
3	65	505	2.55
7	65	570	2.58
8	65	635	2.58
4	65	700	2.58
2	40	740	2.71
14	65	805	2.80
5	95	900	2.84
6	95	995	2.84
15	65	1060	2.86
16	65	1125	2.86
17	65	1190	2.86
18	65	1255	2.86
9	95	1350	2.87
10	37	1445	2.87
3	37	1482	2.96
7	37	1519	3.00
8	55	1556	3.00
13	35	1611	3.04
1	35	1646	3.06
2	37	1681	3.09
4	35	1718	3.12
11	35	1753	3.18
12	37	1788	3.18
15	37	1825	3.27
16	37	1862	3.27
17	37	1899	3.27
18	37	1936	3.31
14	37	1973	3.47
1	55	2028	3.65
11	40	2068	3.65
12	40	2108	3.66
2	23	2131	3.68
13	43	2174	4.60
11	20	2194	4.60
12	20	2214	

figures of incremental fuel cost at each plant. From Table (3), for example, a demand of say 1500 MW could be produced by that plant with an incremental fuel cost of 3.00 mills per kilowatt-hour.

To insure rate stability, a provision to the rate schedule is always attached which will give the necessary adjustment to the rates as a result of fuel cost variation. For example, in the 1973 rate of PG and E, the fuel adjustment is as follows: "The fuel cost adjustment amount shall be the product of the total kilowatt-hours for which the bill is rendered multiplied by 0.159 cents per kilowatt-hour". With that the basic rates remain the same, unaffected by the fuel cost variation.

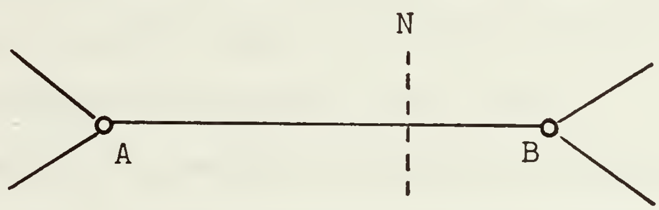
2. Transmission Cost

The variable cost of transmission results from energy loss in the system between the generating plants and the distribution stations. Its finding is made by comparing the annual production and the annual sales recorded at all distribution stations. The difference between those two figures is the annual energy loss or dollar cost due to transmission. Therefore, it is difficult if not impossible to find the exact incremental cost of transmission because of the complicated network of the system and also because transmission is subject to sharply increasing returns.

Boiteux and Stassi [10] offered a method to calculate the marginal cost of transmission for a system consisting of both thermal and hydro plants. Their claim was that the

most economical management of a system of interconnected thermal and hydro plants, both at optimum, is secured by a certain configuration of energy movement. This configuration possesses the following property at every point in time:

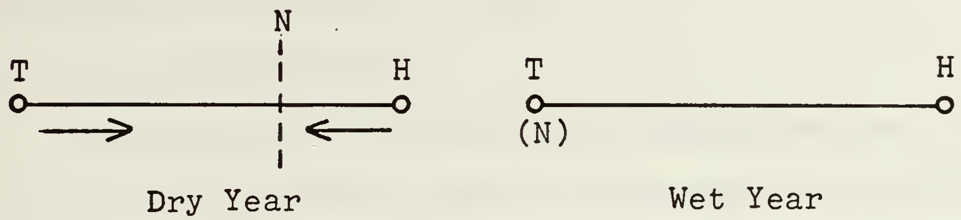
a) On every segment of the transmission network between two nodes A and B (Figure below), energy moves from A where energy is cheaper toward B where it is more expensive, and the marginal cost at B is equal to the marginal cost at A, increased by the marginal transmission cost from A to B.



b) There exists between A and B a neutral point N, where the marginal cost of energy from A, increased by the marginal transmission cost from A to N, is equal to the marginal cost of energy from B, increased by the cost of transmission from B to N.

Therefore it is sufficient to know the marginal costs at one node of the network, and the optimum configuration of energy movements at each moment, to deduce, step by step, the marginal costs at all nodes of the network. This enables a load dispatcher at the central station to send additional load requirements to a certain area at the lowest cost. However, care must be taken since the output of a hydro plant depends upon the water level in the reservoir. Suppose

all thermal plants are concentrated at a single node T, and all hydro centers are at H (see following figures).



In a dry year, the line TH is not at full capacity, and the marginal cost at H is derived from the marginal cost at T by allowing only for losses. The drier the year, the higher the marginal cost at T, the closer the neutral point N will be to H, and the higher the marginal cost at H.

Conversely, the wetter the year, the lower the marginal cost at H. Above a certain level of water supply, the point N will come all the way to T, the, with the substitution of hydro energy increasing in proportion as the year becomes wetter, a moment will come when the line HT will be at full capacity.

The model given above has two drawbacks, i.e., first, the calculation of marginal cost at a node requires the determination of marginal transmission cost from the preceeding node which we know is very difficult to assess except on an annual basis for the entire system. Second, the two node hydro-thermal representation is misleading without further assumptions because the marginal cost of generation in a hydro plant is almost non-existent.

Therefore, we have to settle down with the annual energy loss due to transmission and then averaging it over total sales. In the face of sharply increasing return this is possibly the best way to take.

3. Distribution Cost

In addition to transmission and generation costs, the costs of distribution must be recovered if the principle of "fair" return is to be maintained. The distribution costs increase the expenses of owning and operating lines, distribution stations, and other equipment which serve to connect individual customers to the main transmission network. The distribution costs also cover the energy loss between the distribution stations and customers' premises, billing and metering costs. Annual determination of the distribution costs can be done in the same way as the transmission costs discussed in the previous paragraph. According to a survey conducted by the F.P.C. in 1970 [35] the average annual costs of distribution in the U.S. is equivalent to 5.5 mills per kilowatt-hour sold.

The cost of an individual's connection depends solely on the consumption of the customer and, therefore, he should be charged accordingly. In practice, however, such a scheme would require up to as many different rates as there are customers. To avoid complication, an equal charge is applied to customers within a class. The distribution costs to be allocated to customer classifications include such things as maintenance, general supervision,

and accounting. For example, the cost of maintaining the street lighting system in a given area will be allocated to street-lighting customers, usually municipalities. Here again, we see that the variable cost of distribution includes components that otherwise can be assigned as fixed.

4. Sales Promotion and General Administration

Sales promotion activity generally includes two functions, i.e., customer contracts and sales of new or increased use of the utility's service. It usually includes cost of local and national advertising, demonstrations of utility's availability of service, and others. A close study of cost records by functional activities will provide an adequate segregation to classes of service.

General administration covers the costs of all activities of that nature, including general management, general accounting, property records, etc. Since these costs are of an overhead nature they are spread over all classes of service.

In summary, from the exposition of all elements of operating costs, it is apparent that the marginal operating cost (= b in our notation) is very difficult to determine. This is due to the inclusion of otherwise fixed costs in the variable costs. But since in practice we are more concerned about Equation (42) rather than (34) or (35), such inclusion is perfectly legitimate as long as the resulting revenue requirement is still within the limits of the constraints.

C. DEPRECIATION CHARGES

Changes for depreciation are not current cash payments or obligations. They constitute estimated periodic amounts required for ultimate retirement of plant items as the items become unsuited for efficient and economical operation. The function of depreciation charges is to include in the total current costs appropriate amounts to absorb the costs of the longer life property items during the years of their economic service lives. The purpose is to apportion gradually the original property costs charged to capital accounts at installation to income accounts as cost of operation during the economic service lives of the various property units.

The calculation of depreciation charges, commonly used by U.S. utility companies, is based on the so-called "straight-line" method. This involves equal annual charges which will accumulate during the economic service lifetime of the property units and their original costs (subject to adjustment for their salvage value). Determination of the economic service lifetime of the various property units of a company is a matter of managerial estimate, but it should be subject ot commission approval or requirement. The estimates should be re-examined periodically, and the depreciation percentages should be revised upward or downward as experience reveals that the economic service life of some item is, in fact, shorter or longer than had been previously assumed. In principle, the annual depreciation charges for a plant unit should be equal during its economic service

life, but naturally there are variations if the life estimates are adjusted during the period of its economical operation.

The economic service life of an installed unit, as estimated for the calculation of its annual depreciation charge, extends from the time of its installation and placement in service to the time when its over-all economy in operation has declined to a point where it could be replaced at equal over-all annual cost by a new unit. That point measures the end of the economic service life of the existing unit. It is simple in concept but in application it involves many variables and uncertainties. At the installation of a new plant unit, its economic service life is at best an intelligent guess. Thereafter economic service life will be affected by unpredicted shifts in technological developments, service demands, and changes of price level.

Although straight-line method of calculating annual depreciation charges has been used extensively in U.S. public utility companies, it has the abstract imperfection that it provides equal annual charges for all classes of plant, notwithstanding the fact that some important plant groups are subject ot relatively more intensive use during their earlier years in operation than later. (It is a common practice to meet demand with the most efficient plant which is usually the newest one.) It would therefore seem more correct to have plant unit depreciation provisions determined on an "accelerated" basis.

Where proper accounting has been maintained throughout the past in regard to original plant costs, annual depreciation charges, and reserve accruals, the result can be taken directly from the accounts for rate making purposes or the determination of long-run marginal cost.

In current rate cases, however, there are still conflicts of interest and disputes in regard to proper provisions for depreciation in the annual costs of the company. If the existing reserve is inadequate, the company strives to make up the deficiency through higher depreciation provisions than justified on proper plant cost allocation; the consumers oppose. Conversely, if the reserve is excessive, the consumer side demands a reduction in the annual allowance to bring the reserve down to proper amount; the company opposes. This conflict is mainly due to the imprecise definition of fairness in return and thus with proper regulation the situation can be corrected, hopefully.

D. TAXES

Taxes differ from all other costs in that they are imposed by governmental bodies. They do not depend on company management and are not direct operating costs as such. Nevertheless, they are costs paid by the company and so are properly included in the total annual costs and in the rates paid by consumers. There are two kinds of tax payments or accruals for rate making: a) ordinary or general taxes, and b) income taxes. The former consist of

payments that reflect direct assessments upon properties and activities relating to public service, including franchise or other taxes levied on gross operating revenues. General taxes, regardless of the amounts, are includible in full for rate making. In fact, they are really paid by the consumers. The company merely serves as the tax collecting agency for local, state, and federal governments.

The latter consist of tax payments or accruals on income including excess profit taxes. These are predicated upon the net earnings of the company after provision for operating expenses, depreciation, general taxes, interest, and other deductible allowances. After all deductions from gross utility revenues and nonutility income have been made, the balance of earnings is subject to the income levies as fixed by Congress, or as fixed by the legislative bodies of those states and municipalities that have income taxes.

Because of the high federal income taxes, it is particularly important that a clear-cut perspective be adopted for the purpose of determining proper costs in the fixing of rates. Taxable income consists of net earnings as realized under existing rates - whether they be reasonable, excessive, or inadequate. For this reason, actual payments or accruals obviously cannot be taken directly as cost for the fixing of reasonable rates, unless the existing rates are in face reasonable. If the rates are excessive, the income tax is high accordingly. Thus, if the actual payments or accruals were to be taken as cost for rate making, they would support

the continuance of excessive rates. Conversely, if rates are inadequate, the related low income taxes, if taken for rate making, would correspondingly perpetuate inadequate rates.

The correct principle is, according to John Baver [4], to calculate for rate making purposes the income tax that would be payable under reasonable rates. The amount as derived would be taken as cost of service to be included in the fixing of rates. Application of this principle precludes continued support of either excessive or inadequate rates; it provides for the inclusion of income taxes in accordance with reasonable rates. Hence, for such income tax provisions predicated on reasonable rates, there must be prior determination of the net return to which the stockholders are entitled.

E. THE RATE BASE

The last term of Equation (42) is the amount of allowable return which the company is entitled to. But the amount of this return is usually calculated through the application of a percentage rate (= r in our notation) to a so-called rate base. We now turn to the measurement of this rate base - perhaps the most widely disputed legal issue in the history of public utility regulation.

The rate base is composed principally of the net valuation of the public utility's tangible property, comprising the plant and equipment used and useful in serving the public

(fixed capital). In addition, the rate base includes an allowance for working capital and, depending on the circumstances, may also include amounts for the overhead costs of organizing the business, intangibles, and going concern value. The key issue in the determination of the rate base is the valuation of the public utility's plant and equipment. At the heart of this controversy is the fact that the total valuation of plant and equipment may vary with the particular method of valuation applied. Implicit in this controversy is the fact that the greater the valuation of public utility tangible property, the greater will be the rate base and, therefore, the total cost of service, other things remaining equal. Of course, the reverse is also true. Essentially, there are three valuation methods: a) actual cost less depreciation; b) reproduction cost new less depreciation; and c) "fair value."

1. Actual Cost Methods

Actual cost determinations of public utility tangible property may employ either the historical cost, prudent investment or the original cost method. Historical cost usually can be found by consulting the books and records of the company. In that event, the property element in the rate base is the sum of the amounts actually spent for initial construction, acquisitions, and addition and improvements less depreciation. The historical cost, thus found, plus an allowance for the overhead charges incurred during construction less depreciation would provide a valuation of the tangible property.

The prudent investment method of determining actual cost would subtract from depreciated historical cost any amounts found to be dishonest or obviously wasteful. However, every investment is assumed to be reasonable until the contrary is shown.

A third actual cost method is the "original cost" approach. Original cost is the cost of the property in its <u>first use as public utility plant</u>, less depreciation [4]. The principle advantages of actual cost are administrative simplicity and stability. Administrative simplicity has been made possible in large part by the fact that uniform systems of accounts, set up by the F.P.C., have been put into effect which provide a verified source of data on the costs of property construction and acquisition as well as depreciation. The second principal advantage of actual cost is its stability. The cost of tangible property units, when properly recorded in the company's plant accounts, have not been subject ot unpredictable fluctuation.

But, despite its definiteness, the actual cost can be misleading because, first, it assumes that the dollar is a unit of measure of constant economic size, when it is not. Second, during period of inflation, other things remaining equal, it results in a declining rate of return — as measured in terms of the value of money. In an investor owned utility company, this is a serious situation because both the common stock holders and the bond holders will be affected.

2. <u>Reproduction Cost New</u>

Another method of determining the rate base is known as reproduction cost new less depreciation, or RCND (an abbreviation used by Garfield [22]). The RCND is a measure of the cost of duplicating the existing plant at recent or present prices, less depreciation. One method of assessing RCND is called "trended original cost." This method employs various index numbers of prices in order to convert the actual investment cost experienced by the company into the equivalent value as expressed in current dollars. This is done by multiplying the recorded actual cost of each property unit or class by the ratio of the appropriate index number of prices for the current year to that of the year in which the property unit was installed, as follows:

$$\text{Trended original cost of property unit in current year} = \text{actual recorded cost of the property in year of installation} \times \frac{\text{index number current year}}{\text{index number of the year of installation}}$$

Thus the RCND rate base takes into account changes in the value of money. As a result it is capable of stabilizing the real income of common stockholders in utility enterprises. The use of RCND also can result in flexible rates which are higher when prices are high and lower when prices decline. Higher rates tend to prevent possible artificial

stimulation of the demand for utility services which otherwise might occur if such service were underpriced in terms of the real value of money.

3. Fair Value

The fair-value rate base is a composite which gives weight to both depreciated actual cost and RCND. The amount of weight given to each of these indications of value may, according to Garfield [22], vary from case to case and also from State to State. Whatever the percentage may be given to each, the sum of both becomes the fixed part of the total fair-value make-up besides working capital and going-concern value.

It would seem that in any case the total of fixed capital and working captial would be enough to cover the full range of corporate investment to be compounded into a total amount of fair-value. But to this total value had to be added the separately "going-concern" value. Going-concern value is the excess valuation over fixed capital which arises due to the fact that the assets are in operation, with established management, employees, experience and customers, and with assumed potentials of service expansion.

Since the determination of going-concern value is highly subjective, it is of course open to serious questions as to its fairness to the consumer. Therefore it should be abandoned and be replaced by a more reasonable measure such as increasing the amount of working capital, if it is so desired.

In the course of discussion in Section II we came to the conclusion that for a rigid plant the cost function is well approximated by a linear one of the form

$$C(q_1,q_2,K) = bq_1 + bq_2 + \beta K$$

where b is the short-run marginal cost and β is the long-run marginal cost (the cost of providing a unit of capacity). However, it has been the conclusion of this section that the determination of marginal cost is extremely difficult if not impossible. What we can get, and that used in practice, is the average cost. The method introduced by Da Silva for determining the short-run marginal cost of generation is perfect as long as the company owns only one type of generation plant, i.e., thermal. In the case of a mix of hydro and thermal plants where the percentage of hydro plants is substantial, averaging the total marginal costs of the entire utility plants is unavoidable, except, if we are willing to use the marginal cost of generation of the thermal plant as representing the whole utility generating plants. Since the short-run marginal cost of generation of a thermal plant is greater than that of a hydro-plant, taking this step means a gain for the utility company. However, the possibility of calculating marginal cost stops here, because of the fact that in transmission and distribution, the cost can be determined only for a specified period. Whence, average cost is the only possible result.

The RCND method of evaluating the net assets is clearly better than the actual cost because of the fact that it takes into consideration the change in money value. The fair-value method is the worst of the three and since today it is used only by a few minor companies, the retirement of that method is advisable.

IV. COST DISTRIBUTION

A. GENERAL

The costs of electric generation, transmission and distribution are maintained in the uniform system of accounts prescribed by each commission for the utilities under its jurisdiction. In addition, each utility files a detailed annual report with the commission, with all data stated on the basis of the accounts and sub-accounts of the prescribed accounting system. Cost data in this form are not directly usable in cost analysis developed to aid in the design of rates. Accordingly, it is necessary to undertake the following procedure: a) classification of the total cost of service into three basic categories, called customer costs, energy costs, and demand or capacity costs; b) allocation and distribution of the classified costs to customer classes or types of load; and c) totaling the customer, energy and capacity costs thus assigned to each customer class to provide a basis for determining the average costs of supplying the respective classes of service.

The classification of costs to the customer, energy and demand categories was first proposed by W.J. Greene in 1896, and now it is the most widely used in the United States. Houthakker [18] divides the total cost of service into four categories, by adding to those mentioned a fourth, residual costs.

The customer costs are those operating and capital costs found to vary with number of customers regardless, almost, of power consumption. Included as a minimum are the costs of metering, billing, collecting and accounting (as an example, residential customers in the Monterey area are charged, in 1973, $0.65 per month of customer charge and $0.65 per month of minimum charge). Customer costs may be distributed to respective groups in proportion to the number of customers in each one. The really controversial aspect of customer cost imputation, as indicated in the previous section, arises because of the common practice by the utility company of including not just those costs that can be definitely earmarked as incurred for the benefit of specific customers but also a substantial fraction of the annual maintenance and capital costs of the secondary (low voltage) distribution system. Their inclusion among the customer costs, according to Bonbright [11], is defended on the ground that, since they vary directly with the area of the distribution system (or else with lengths of the distribution lines, depending on the type of the distribution system), they therefore vary indirectly with the number of customers. This reason is, of course, very hard to accept because the area where the utility operates is almost constant over the years. What actually happens is that, all the un-allocated costs remaining are "dumped" in the customer-cost category as a result of the company's determination to fully distribute total costs of service among customers. It is therefore not surprising

that Houthakker added the fourth category, residual costs, in his total costs division as a means of coping with the difficulty of un-allocated costs. The following table is an example of the above discussion, the inclusion of a substantial fraction of the annual maintenance and capital costs of the secondary distribution system, a practice of the PG and E:

TABLE 4

Summary of Classification of Rate-base Items to Demand, Customer, and Energy Component

Items	% relationships after direct assignments		
	Demand	Customer	Energy
Distribution system:			
Land, structures and station equipment	100	-	-
Poles, Tower, O.H. conductor	30	70	-
U.G. conduit and conductor	60	40	-
Line transformers	75	25	-
Services	55	45	-
Meters, miscellaneous	-	100	-
General, Material and supplies	55	45	-
Working capital	40	58	2
Contribution and Advances	-	100	-

The energy-cost category of the three-fold division of the total annual costs is supposed to consist of those costs which would vary with the changes in consumption of energy, measured in kilowatt-hours, even if the number of customers should remain constant and even if there were no change in maximum load upon the system or subsystem as measured in kilowatts or kilo volt amperes. The most obvious costs of this character are fuel costs, although a small portion of these costs may be regarded as demand-related on the ground that some fuel is required in order to maintain spinning reserve, that is, to keep the quality of service from deteriorating in the advent of a sudden increase in demand.

Energy cost may be distributed to customer groups on the basis of kilowatt-hours of energy consumed in the test period, or kilowatt-hours plus energy losses. The relative kilowatt-hour consumption of customer classes determines how much of the total energy related costs was assigned to each class. Table (5) is an example of energy costs allocation to customer classes (that of PG and E), the summary of which is as follows:

Sales adjusted to transmission input:

Class of Service	% allocation
Domestic (residential)	33.55
Commercial	34.90
Industrial	23.70
Agricultural	7.04
Street lighting	0.81
	100.00

DERIVATION OF COMMODITY ALLOCATION FACTORS
(PG and E; YEAR 1975 ESTIMATED)

TABLE 5

SALES ADJUSTED TO TRANSMISSION INPUT:

Line No.	Class of Service	Sales Kwhr (000 Omitted) (A)	Sales as % of Transmission Input (B)	Transmission Input Kwhr (000 Omitted) (A)÷(B) (C)	% (D)	Line No.
1	Domestic	17,811,000	88.1	20,216,800	33.55	1
2	Commercial	18,674,000	88.8	21,029,300	34.90	2
	Industrial:					
3	Transmission Level	411,000	97.5	421,500	0.70	3
4	Distribution Level	12,474,000	90.0	13,860,000	23.00	4
5	Total	12,885,000		14,281,500	23.70	5
6	Agricultural	3,772,000	88.9	4,243,000	7.04	6
7	Street Lighting	432,000	88.6	487,600	0.81	7
8	Total	53,574,000		60,258,200	100.00	8

SALES ADJUSTED TO DISTRIBUTION INPUT:

Line No.	Class of Service	Sales Kwhr (000 Omitted) (E)	Sales as % of Distribution Input (F)	Distribution Input Kwhr (000 Omitted) (A)÷(B) (G)	% (H)	Line No.
9	Domestic	17,811,000	91.8	19,402,000	33.78	9
10	Commercial	18,674,000	92.5	20,188,100	35.14	10
11	Industrial	12,474,000	93.7	13,312,700	23.18	11
12	Agricultural	3,772,000	92.6	4,073,400	7.09	12
13	Street Lighting	432,000	92.3	468,000	0.81	13
14	Total	53,163,000		57,444,200	100.00	14

Sales adjusted to distribution input:

Class of Service	% allocation
Domestic (residential)	33.78
Commercial	35.14
Industrial	23.18
Agricultural	7.09
Street lighting	0.81
	100.00

Recall also that it is customary for the utility company to include a fraction of the maintenance costs of the generating plant in the energy-cost make-up.

The capacity costs include the major part of the total allowance for depreciation, taxes, insurance, return on investment and a substantial part of the operating and maintenance expenses. In accounting terms, this cost component is called the annual fixed changes. The following figures are of typical U.S. utility company (F.P.C.'s figures):

TABLE 6

Fixed Charges Rate - 30 Years Service Life of Conventional Steam Generating Equipment

Cost of money	8.2%
Depreciation and replacements	1.2%
Insurance	0.2%
Income taxes	2.2%
Other taxes	2.4%
Total	14.2%

Assuming that the annual fixed charges have been determined, the question arises as to the proper apportionment among, or allocation to, services supplied at different load factors and at different times of day or season. These services share responsibility in different degree for the creation of the system and sub-system peak loads and indirectly for the capacity costs.

Demand or capacity costs require an allocation to classes of customers on the basis of one of the many formulas available for this purpose. The most commonly used in the United States are: a) the peak responsibility formula, b) the non-coincidental-demand formula and c) the average-and-excess-demand formula.

B. ALLOCATION OF DEMAND COSTS

1. Peak Responsibility Method

Here, the entire capital costs are imputed to those services that are rendered at the time of the system peak (or sub-system peak) and in proportion to the kilowatt demand imposed at this time - an integrated demand rather than instantaneous demand, measured over some short period of time such as thirty minutes or longer. Service rendered completely off-peak would be assigned no responsibility whatever for the capacity costs. This method, therefore, is in complete agreement with the results given by Boiteux, Steiner, Mohring and Pressman. Thus, for example, with a system peak load of 1000 kw, the allocation would be

determined as follows:

Class Load	Peak Responsibility	Allocation Percentage (%)	Capacity Allocated
A	400 KW	40	400 KW
B	0	0	0
C	600	60	600
	1,000	100	1,000

In applying the peak responsibility method to a group of individual customers, the load factor versus coincidence relationships introduced by Bary [2] is commonly used.

Bary recognizes the existence of the relationships between load factor and coincidence factor of individual customer in a group. It should be noted that load factor versus coincidence approach may not be applicable in the case of a single customer whose load represents a large percentage of the utility's total load system. A typical Bary curve for groups of small customers is represented in Figure (2). The diagonal line on that figure, running from zero to 100% load factor marks the theoretical lower limit of coincidence for large groups of customers; the upper limit is, of course the 100% coincidence line.

Figure (3) portrays, as an example, a hypothetical load factor-coincidence pattern for a small group of large customers. The coincidence factor for each customer spotted on the figure is the ratio of his demand, at a specified

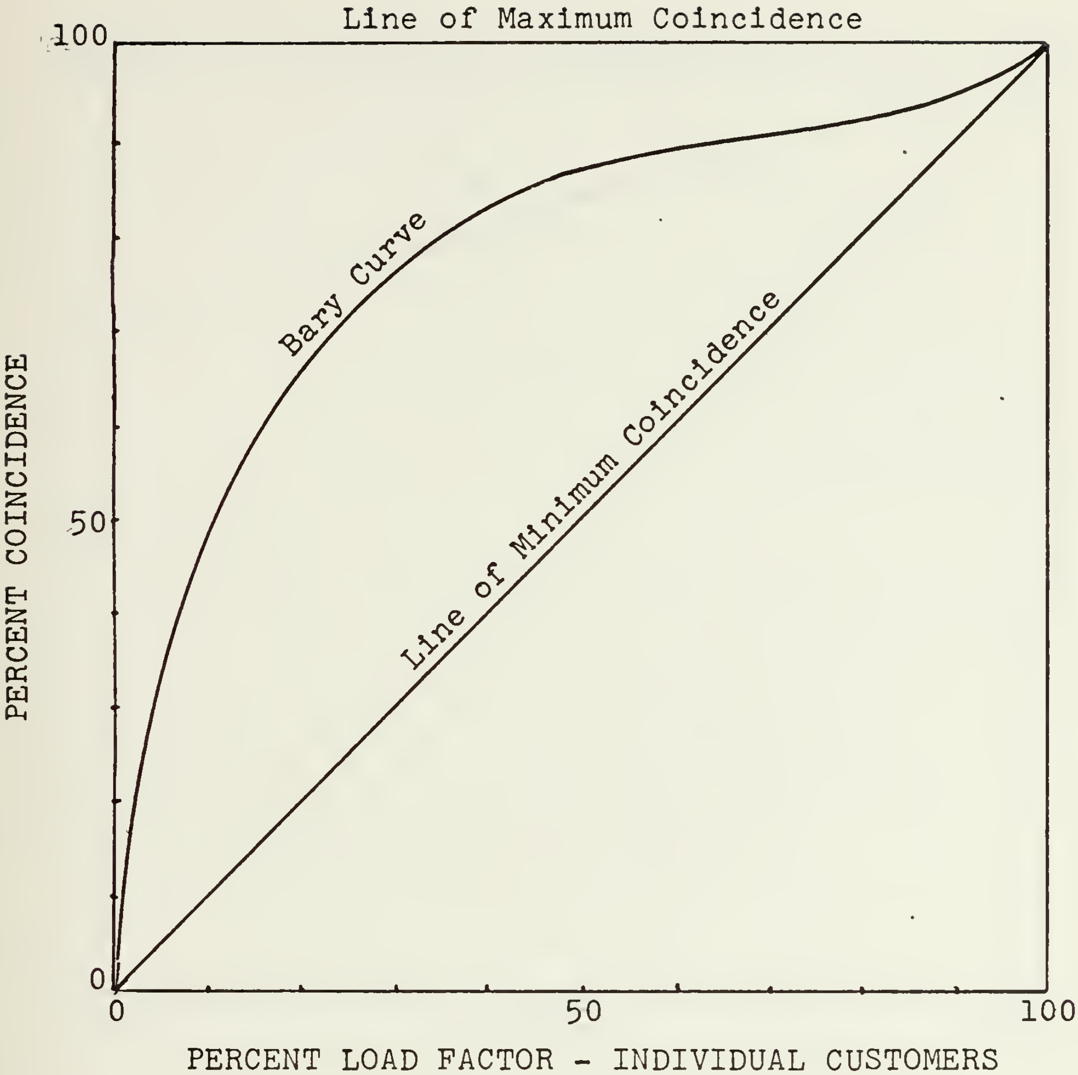


FIGURE 2. BARY CURVE

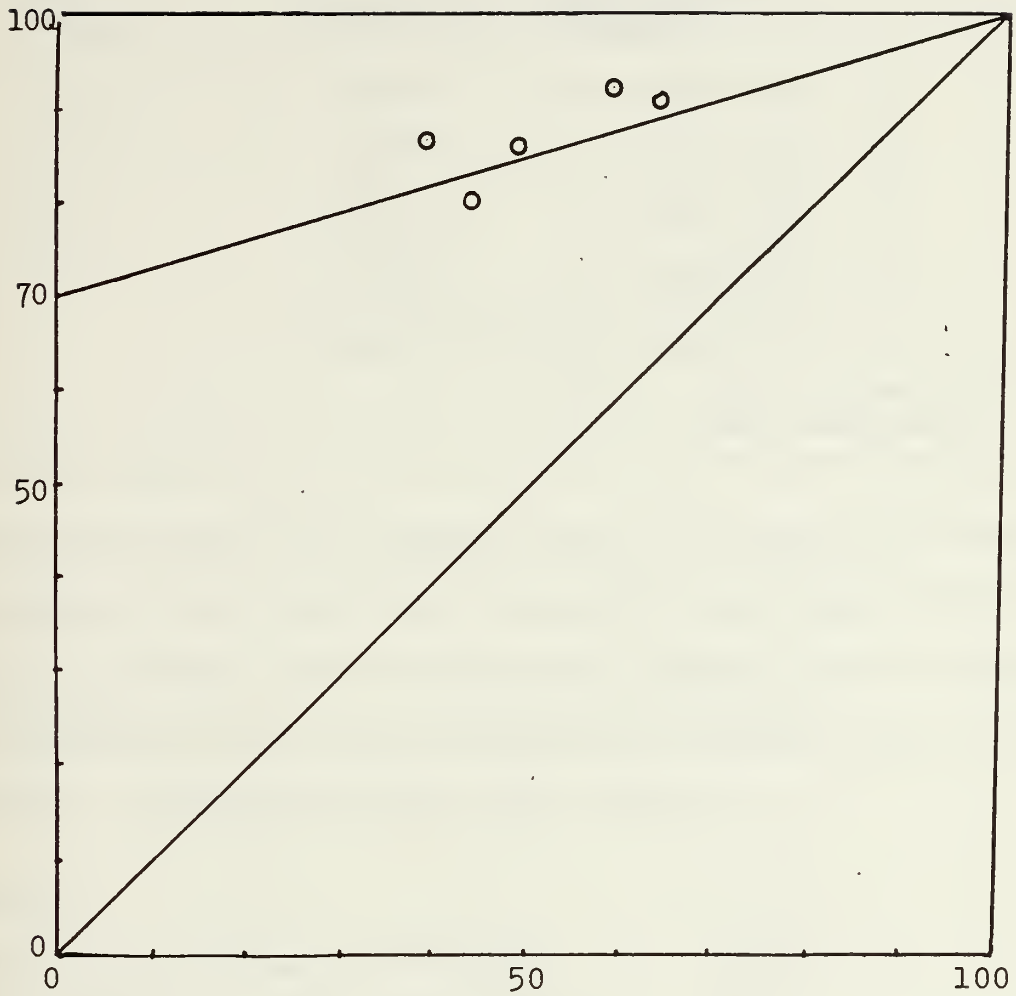


FIGURE 3. BARY PLOT FOR FIVE HYPOTHETICAL CUSTOMERS

Plot Points:

Point No.	Load Factor	Coincidence
1	40%	0.850
2	45%	0.775
3	50%	0.830
4	60%	0.920
5	65%	0.905

time, to his maximum demand during the period being studied. The zero load intercept of the straight line fit for those five data points can be computed as follows:

Load Factor	Coincidence Actual		Coincidence Formula
40 %	0.850		x + 0.40(1.00 - x)
45	0.775		x + 0.45(1.00 - x)
50	0.830		x + 0.50(1.00 - x)
60	0.920		x + 0.60(1.00 - x)
65	0.905		x + 0.65(1.00 - x)
	4.280	=	6x + 2.60(1.00 - x_
	x	=	0.70 this is the zero load intercept

Using this method, the demand charge is based on the capacity cost at 100% load factor times the coincidence factor at zero load factor, and the remaining capacity cost is included on a kilowatt hour basis by spreading over the hours in the period; a Hopkinson demand rate results.

Example:

capacity cost per KW per month : $3.00
coincidence at zero load factor : 70%
730 hours of operation in a month

demand charge = $3.00 x 0.70 = $2.10

$$\text{capacity cost in energy charge} = \frac{\$3.00 - \$2.10}{730}$$

$$= 1.23 \text{ mill/KWH}$$

Therefore, the enrgy charge would be added to the 1.23 mills figure in setting up a rate.

2. Non-Coincidence Demand Method

The non-coincidence demand method is also known as maximum demand method. The theoretical basis of this method provides that joint-demand costs incurred in serving a number of customer groups should be allocated in proportion to the facilities necessary to serve each customer group separately. Accordingly, this method looks to class peak demands, regardless of the time of the occurence. These steps are required: a) the peak demands of each class, regardless of time of occurrence, are added to find the sum of the maximum class demands; and b) allocation of system demand costs to each class is calculated on the basis of ratio of each class peak to the sum of the maximum demands. For example:

Class Load	Class Peak	% Allocation	Capacity Allocated
A	1,500 KW	50.00	1,000 KW
B	500	16.67	334
C	1,000	33.33	666
	3,000 KW	100.00 %	2,000 KW

In actual practice, the load factor of each class of service is taken into account to arrive at the percentage of allocation. The following example is a calculation, by PG and E, for residential class:

- Average demand (MW) = 2,033.2 MW
- % load factor = 41%
- Maximum demand = $\frac{2,033.2}{0.41}$ = 4,959.0 KW
- Demand as % of distribution input = 90.4%
- Demand at distribution input = $\frac{4,959.0}{0.904}$ = 5,485.6
- Total demand of all classes at distribution input = 13,485.8 MW
- % allocation to residential class = $\frac{5,485.6}{13,485.8}$ = 40.68%

3. The Average Demand-and-Excess Method

The average demand-and-excess method was introduced by Caywood [12] and is also widely used in the United States. With this method, the portion of facilities required to serve the average load is allocated on this basis, and the remainder is allocated by applying the non-coincidence demand method.

This method avoids the shortcomings of both peak responsibility method and the non-coincidence demand method, in as much as maximum loads, rather than loads at the time of the system peak, are used and the extent of use of equipment is taken into account. For example:

Class load	Max. demand	% load factor	Allocation
A	500 KW	50	371 KW
B	200	100	200
C	800	10	429
	1,500 KW		1,000 KW

The necessary computations are as follows:

- Average load = (0.50 x 500) + (1.00 x 200) + (0.10 x 800) = 530

- Excess load = 1,000 - 530 = 470
  (the total allocated demand of 1,000 KW can be found using the non-coincidence method)

- Average load allocation:

A	=	250	KW	=	250 x 8960	=	2,190,000	KWH per year
B	=	200	KW	=	200 x 8760	=	1,752,000	"
C	=	80	KW	=	80 x 8760	=	700,800	"
		530					4,642,800	

- Excess load allocation:

  Excess loads:

A	=	500 - 250	=	250
B	=	200 - 200	=	0
C	=	800 - 80	=	720
				970
				530
				1,500

  Allocation:

A	=	250 x 470/970	=	121
B	=	0 x 470/970	=	0
C	=	720 x 470/970	=	349

  Total:

A	=	250 + 121	=	371
B	=	200 + 0	=	200
C	=	80 + 349	=	429
				1,000

The average-and-excess demand method can also be worked out by formula, using two equations given us by Greene:

$$Kx + Dy = C$$

and

$$8{,}760x + y = \frac{C}{P}$$

where:

C = total annual cost
P = maximum demand of the system
D = sum of class demands
K = total energy use
x = cost per KWH for capacity related to energy
y = cost per KW for capacity realted to load

Using the above example for values of P, D and K; and assuming further that C = \$50,000, we get:

$$4{,}642{,}800x + 1{,}500y = \$50{,}000$$

$$8{,}760x + y = \frac{\$50{,}000}{1{,}000}$$

And the solutions are: x = 2.94 mills
y = \$24.23

Allocation for loads A, B and C are:

A	=	2,190,000	x	2.94 mills	+	500	x	\$24.23	=	\$18,550
B	=	1,752,000	x	2.94 mills	+	200	x	\$24.23	=	\$10,000
C	=	700,800	x	2.94 mills	+	800	x	\$24.23	=	\$21,450
		4,642,800				1,500				\$50,000

The above result checks with the allocations made by the long method, that is,

A =	371	x	\$50	=	\$18,550
B =	200	x	\$50	=	\$10,000
C =	429	x	\$50	=	\$21,450
	1,000				\$50,000

The load factor-allocation curve for the average and excess demand method is a straight line, and its zero intercept can be determined by the following formula:

$$\text{Class allocation} = \frac{\dfrac{(SP-SAL)(CP-CAL)}{\text{Sum }(NCP-SAL)} + CAL}{CP}$$

where:

SP = system peak
SAL = system average load
CP = class peak
CAL = class average load
NCP = non-coincident peak.

V. TARIFF STRUCTURE

A. GENERAL

The following terminology is used in discussing the tariff of an electric utility:

a) Rate; the prices for electric service

b) Schedule; the rate plus several provisions necessary for billing for various load conditions of customers

c) Rules and regulations; a statement of the general practices the utility follows in carrying on its business

d) Tariff; all the schedules and rules and regulations of the utility.

Rates for electric service are nothing more than price tags which the electric utility places on the service it renders. Well-rounded rates integrate within themselves the essential policies and practices of the utility with respect to:

a) Engineering of the supply system (such as design, voltage standards, minimum reserve etc)

b) Operation of the supply system (such as maintenance standard, operating reserves, equipment loading, etc)

c) Accounting (such as depreciation standards, method of valuation, etc)

d) Finance (such as ratios of capital structure, dividend pay-outs, etc)

e) Sales (such as direction of promotional efforts, administration of contracts, etc)

f) Legal (such as franchise requirements, state laws for utilities, etc).

B. PRICING POLICIES

Pricing is the final step in the over-all rate-making process. Under the conventional practice, as discussed in Section III, pricing becomes a matter of regulatory concern after commission determination of the utility's approved cost of service, including a fair return. Public utility rates are intended to accomplish much more than to produce revenues equivalent to the approved cost of service. They are also intended to apportion the company-wide cost of service among consumers in a reasonable manner and to provide an effective instrument for the marketing of public utility services.

Unlike some of the matters considered up to this point, such as rate base, depreciation, operating and maintenance costs, and rate of return, there has been relatively little controversy in the area of rate structures. The following are the basic rate-making principles and practices which have become generally accepted through the years in the United States.

1. Differential Pricing

It would be ideal if the utility could sell electric service on one simple rate at a single price of, say, 2 cents per kilowatt-hour. Customers would easily understand such rates, and billing would be simplified, and overhead costs would be reduced. However, the utility cannot take

advantage of this rate utopia because of the wide differences in customers' electric service requirements. Also, if an attempt were made to sell all service at one average price, the utility would lose the business of those customers who could obtain kilowatt-hours at a cheaper price from some other source, and rates for remaining customers would go up. Instead, a) relatively homogeneous groups of customers, called customer classes, are established; b) a different schedule is applied to each class; and c) each ordinarily offers the individual customers within each class a graduated, descending scale of rates for incremental blocks of service taken. Accordingly, public utilities engage in "differential pricing" rather than uniform pricing, primarily because different schedules of rates apply to different classes of customers such as: residential, commercial, industrial, rural area, street lighting, etc. Three conditions are necessary, according to Liebhafsky [23], in order for differential pricing to be possible, i.e. a) monopoly or near monopoly; b) a total demand that can be subdivided into separate markets, each with different price elasticities of demand and c) some means of insulating each market from others, so that those who buy at the lower prices cannot resell to those who would have to pay higher prices. As we have seen in Section II, public utilities fit into this pattern very well and thus differential pricing can be justified.

The classification of customers is based upon two principal factors, i.e. the "size" of the consumer - as measured by the number of kilowatt-hours consumed per month or the maximum demand or both, and the purpose to which the public utility service is devoted [FPC Survey 1970]. Other factors taken into account may be the quality of service, the time at which the service is required, and the stability of demand from year to year. Each schedule states in detail the class of customers to which it applies, the nature of the service to be provided, the method of calculating the bill, and other terms and conditions affecting the sale.

2. General Objectives of Utility Pricing Policies

A public utility's rate structures were designed to accomplish the following general objectives: a) produce revenues equivalent to the approved cost of service, b) maximize utilization of fixed plant, c) assure maximum stability of revenues, d) distribute the total cost of service reasonably among different classes of customers, and e) promote and retain the maximum economic development of its market.

Except for the first objective, practical necessity often requires a balancing of objectives when the fullest achievement of one conflicts with the fullest achievement of another. To accomplish these ends, the guiding principle in the design of rate structures calls for consideration of both: the costs, or relative cost differences of supplying each class of customers or service; and the value of service or, in other words the demand characteristics of the different

segments of the total market served by the utility. The first of these is a recognition of the demand side, while the latter is a reflection of the supply side of the market.

3. Value of Service

The term value of service, in the context of public utility pricing principles, refers to the conditions of demand which characterize the different segments of a utility's market. In Jefferson's words [20], "the rate man's term value of service happens to be the same as the economist's term elasticity of demand". Thus a low value of service corresponds to an elastic demand and a high value of service corresponds to an elastic demand. Recall, that Pressman (in Section II) developed his mathematical formulation of variable load pricing along the line of the value of service which he incorporated in his consumers' surplus concept. So did Steiner [31], Manne [27] and others. As a result of the above, in the matter of pricing utility services, it would be erroneous to look solely to the result of cost analyses, for they cannot provide useful information with respect to the value of such services on what the public may be willing to pay for them.

C. RATE FORMS

It is a generally accepted principle of public utility rate making that differences in the conditions of demand, as among the respective customer classes, indicate that each class has a different capacity and willingness to bear

charges. Accordingly, with reference to value of service factors, rates are made so as to distribute the approved company-wide cost of service in relation to the capacity and willingness of the customer groups to bear such cost.

There are two basic forms of electric rates in use in the United States for general classes of service: one employs energy use as the sole parameter for pricing of service rendered, and the other employs energy use and maximum demands as dual parameters of the service rendered. The controlling characteristic of the first type is the energy used by customers, and the second type, the customers' load factors and their demand for capacity. There are other types, but they are confined to special applications.

1. Flat Demand Rate

The flat demand rate consists of a price of so much per kilowatt for a specified time, say, a month or year. Such a charge is possible where the use of the equipment and, therefore, the kilowatt-hour consumption are known. The charge is normally based on connected load, so that metering is not required. The prices may be "blocked", or discounts varying with total gross bill (quantity discounts) may be used to give lower charges for larger loads. This type of charge is often used today fro street lighting service, in which case the burning schedule is under the control of the utility. The following is an example of quantity discounts:

First $100 of gross monthly bill		net
Next $400 " " "		5% discount
Next $1000 " " "		15% discount
Additional " " "		25% discount.

The difference between the initial discount and the final discount constitutes what might be termed a customer charge. In the above example, this amount is:

$$\begin{aligned}
(25\% - 0\%) \times \$100 &= \$25 \\
(25\% - 5\%) \times \$400 &= \$80 \\
(25\% - 15\%) \times \$1000 &= \$100 \\
\hline
\text{Customer charge} &= \$205
\end{aligned}$$

Thus, for gross monthly bills of $1,500 or more, the net bill may be calculated by the following formula:

$$(100\% - 25\%) \times \text{gross bill} + \$205.$$

2. <u>Block Meter Rate</u>

The block meter rate specifies certain prices per kilowatt-hour for various kilowatt-hour blocks, the price per kilowatt-hour decreasing for succeeding blocks. The rate is simple, easily understood by customers, and widely applied today to residential and other small users. In its basic form, it does not recognize the demand element. The following is a block meter rate for Monterey area in 1973 [PG and E schedule D-3].

First	50 KWH, per KWH	4.529 ¢
Next	50 KWH, per KWH	3.429 ¢
Next	100 KWH, per KWH	2.429 ¢
Next	100 KWH, per KWH	1.629 ¢
Next	700 KWH, per KWH	1.529 ¢
Over	1000 KWH, per KWH	1.329 ¢

plus

customer charge $0.65

a modification of the block meter rate with a minimum charge is the so-called initial charge rate. This form has a first kilowatt-hour block for a certain total amount, which is also a minimum charge. For example, the PG and E schedule A-3 for Monterey area in 1973 is:

customer charge	$0.65
energy charge (in addition to customer charge):	
First 100 KWH, per KWH	4.529 ¢
Next 200 KWH, per KWH	4.029 ¢
Next 700 KWH, per KWH	3.729 ¢
Next 2,000 KWH, per KWH	3.129 ¢
Over 3,000 KWH, per KWH	2.029¢
minimum charge per month	$0.65

The end blocks are usually priced low enough to induce larger use, but high enough to recover deficits produced by customers with small use and to cover cost of service at a specified diversified load factor for larger uses. Bary [ ] proposed an additional provision, i.e., the minimum earned rate to

the above schedule as a protection against the possibility of lower diversified load factor in the very high energy use region.

3. Hopkinson Demand Rate

In 1892, Dr. John Hopkinson proposed a two-part rate consisting of separate charges for demand and for energy and thus recognizing load factor. This type of rate is used mostly for medium- and large-sized commercial and industrial loads. Either the demand charge or the energycharge or both in the Hopkinson demand form of rate may be block to give lower prices for higher loads and greater consumption. This rate form is known as a block Hopkinson demand rate. Again as an example, let us look at the PG and E Schedule A-13:

Demand charge:

First 1,000 KW of billing demand	\$1,500.00
Over 1,000 KW of billing demand, per KW	\$ 1.00

Energy charge:

First 100 KWH, per KWH	1.249¢
Next 200 KWH, per KWH	0.749¢
All excess, per KWH	0.679¢

The fixed amount or the customer charge is developed as follows:

$$(\$1.50 - \$1.00) \times 1000 \text{ KW} = \$50$$
$$(1.249¢ - 0.679¢) \times 100 \text{ KWH} = \$57$$
$$(0.749¢ - 0.679¢) \times 200 \text{ KWH} = \$14$$
$$\text{customer charge} = \$121.$$

Thus for a load of over 2000 KW and energy use of over 300 KWH the billing can be computed using the following formula:

monthly bill = \$121 + \$1.50 per KW + 0.679¢ per KWH.

4. <u>Wright Demand Rate</u>

Arthur Wright was the second British engineer to design a rate form recognizing both load and energy, in which there are a number of energy blocks with decreasing prices for succeeding blocks and in which the sizes of the energy blocks increase with size of load. The effect is to give demand and energy charges. Load factor is thus recognized. The hours'-use rate is applied mostly to medium-sized customers, but in some cases it is used for extremely large loads. Discounts, varying with the total gross bill, are sometimes applied to give lower prices for larger loads. For example:

First 50 hours' use per month or 50 KWH per KW of demand, per hour	3¢
Next 100 hours' use, per hour	2¢
Additional, per hour	1¢

Assume a load of 200 KW and a monthly use of 60,000 KWH, the bill is calculated as follows:

(50 hours' use x 200 KW) x 3¢ = 10,000 x 3¢ = \$300
(100 hours' use x 200 KW) x 2¢ = 20,000 x 2¢ = \$400
30,000 x 1¢ = \$300
Total bill = \$1,000

The demand charge can be developed as follows:

(3¢ - 1¢) x 50 hours' use	= $1.00
(2¢ - 1¢) x 100 hours' use	= $1.00
demand charge	= $2.00

Thus for usage of more than 150 hours per month the billing formula is

monthly bill = $2.00 per KW + 1¢ per KWH.

This rate in effect gives the same price per KWH for the same load-factor for any load, unless quantity discounts or some other device is used to recognize load size. A combination of the block meter rate and the Wright demand rate is commonly used now, particularly for small customers.

D. FUEL COST ADJUSTMENT

As shown in Section III, the cost of fuel is a major item of expense. For this reason, a fuel cost adjustment is often used to permit a utility to follow the variations in fuel costs either up or down. The following examples are given by Caywood [12] in terms of coal price. The examples are based upon the following assumptions:

- base coal price of $5.00 per ton
- base coal price of $0.20 per million BTU
- 12,500 BTU per pound of coal
- line efficiency of 90%, giving 15,556 BTU (based on 14,000 BTU)
- average heat rate 14,000 BTU per net kilowatt generated
- coal cost up 25¢ per ton of coal or 1¢ per million BTU from box price.

1. Type-A Adjustment

The energy charge will be increased or decreased at the rate of 0.156 mill per KWH for each 25-cents increase or decrease in the price of coal above or below the base price of $5.00-per ton. The calculations are:

$$\frac{25 \times 10^6 \text{ BTU per ton}}{15{,}556 \text{ BTU per KWH}} = 1{,}607 \text{ KWH per ton.}$$

and
$$\frac{25¢ \text{ per ton}}{1{,}607} = 0.156 \text{ mill.}$$

2. Type-B Adjustment

The energy charge will be increased or decreased at the rate of 0.156 mill per KWH for each 1-cent increase or decrease in the price of coal above or below the base price of 20 cents per million BTU. The calculations are:

$$\frac{1{,}000{,}000}{15{,}556} = 64.3 \text{ KWH per million BTU}$$

$$\frac{1¢}{64.3} = 0.156 \text{ mill.}$$

The type A adjustment is widely used because the terminology is easily understood. However, the type B adjustment is more sensitive to actual changes in fuel costs, inasmuch as it is based on heat units rather than on tons. (PG and E uses type B adjustment, and their figure is 0.159 mill). In some clauses, there are two base prices, a lower value below which charges are decreased and an upper value above which charges are increased. The range in between needs no adjustment at all.

E. BILLING DEMAND PROVISIONS

Several factors enter into the calculation of billing demand, as part of the schedule provisions. Load peaks may be for different time intervals; a single peak may be used or several peaks may be average; the instantaneous peaks of highly fluctuating loads may be recognized; kilowatt loads may be corrected for power factor; and off-peak loads may be related to loads created during on-peak hours and taken at a reduced value.

1. Peak Width and Peak Averaging

Where measured demands are used for billing, peak width of 5, 15, 30, and even 60 minutes are used. Sometimes only a single peak is recognized [Boiteux and Stassi]; then again two or more daily peaks [Williamson, Houthakker] or weekly peaks may be averaged [Bary]. Peak width and peak averaging can theoretically be tied in with the level of the demand charge, so that a narrow single peak and its demand charge will give the same over-all result as a wider peak or an average of several peaks. Connected load count is sometimes used instead of metered demands, particularly for small loads where the revenue involved is not sufficient to justify the expense of demand metering. Usually a percentage of the connected load is taken to recognize diversity.

2. Instantaneous Peaks

High peaks of short duration are common for loads of equipment such as hoists. A charge is often made for such

peaks when they materially exceed the basic peak used in a schedule. Such a charge is justified because of the higher capacity equipment needed to give proper voltage regulation under such conditions.

3. Voltage Discount

This is a discount applied to demand, kilowatt-hour consumption, or total bill to recognize lower utility costs when the customer does some of the transforming to lower voltages. The amount of discount depends upon the size of the load and the source of the supply, i.e., froma 22KVOLT service or higher voltage service.

4. Power Factor

The economic approach is to make the power factor charge represent the cost to the utility of supplying corrective capacity. Conceptually, then, if the customer can correct for power factor at a cost cheaper than the charge in the rate, he will do so, and the most economical result will be obtained. In determining utility costs, any expenses relative to additional voltage regulation made necessary by the customer's capacitor installation should be included. (The utility gains when capacitors are installed on individual machines because this aids in voltage regulation by keeping the voltage from rising as high when the load is reduced as it does when capacitors are on the main switch.) Utility policies regarding the treatment of the power factor in rates vary widely, as indicated by the following approach:

a) Charge on the basis of kilowatts with the utility correcting for power factor and, in effect, averaging the cost over all customers.

b) Charge on the basis of kilowatts, assuming that bad power factor conditions will be corrected by the customer to realize advantages in his own plant.

c) Make a power factor charge. Some utilities recognize power factor improvement by the customer only when the customer's corrective equipment is installed according to utility requirements.

Power factor provisions are not normally found in rates for small loads because of the high cost of metering compared with revenue received from the charge, the added schedule and billing complications, and above all the difficulty of explaining power factor to the customers. Billing on the basis of kilowatt load time the ratio of a base power factor to actual power factor is commonly used, where the base power factor is taken at 80% or 85%.

5. <u>Minimum Charge and Demand Rachets</u>

A minimum charge of a fixed amount or of so much per unit of billing demand is usually included to give the utility some revenue from the convenience user or of the low load factor customer. In the case of rates having a demand charge, this charge is usually the minimum. It is common practice in the case of larger loads to base the minimum or demand charge on a ratcheted demand, that is, the highest

demand of the last 12 months, the highest of the term, the average demand of the last 12 months, or some percentage of values such as these.

6. <u>Term</u>

Schedules for larger loads in particular carry term provisions which require that the customer sign a contract for a specified period during which he is committed to certain minimum payments.

VI. IMPACTS OF ENVIRONMENTAL QUALITY STANDARDS ON ELECTRIC POWER GENERATION

A. GENERAL

Currently, more than 80% of the electric energy produced in the United States is generated by steam-electric plants. At the exhaust of a steam-electric plant turbine, the steam is condensed to water to maximize the energy conversion and then is returned to the boiler or reactor for a repetition of the cycle. A large amount of heat is rejected in the condensing process. All waste heat from steam-electric plants must eventually be dissipated to the atmosphere. Some heat is transferred directly to the ambient air and, in the case of fossil-fueled plants, some heat is discharged up the stacks. However, the bulk of the waste heat is transferred from the steam to the cooling waters in the condensers. Waste heat discharged to water bodies, which contributes to physical and biological changes, is called the thermal pollution. Growing concern for environmental protection is increasingly requiring the reduction of waste heat discharged to water bodies.

Beside the efforts in reducing thermal pollution, reducing air pollution from fossil-fueled steam-electric plants to acceptable levels is one of the major challenges facing the electric utility industry. The most significant air pollutants associated with power plants are carbon monoxide (CO), sulfur oxides (SO_x), nitrogen oxides (NO_x), hydrocarbons (HC),

and particulate matter. Because of the amounts released and because of their potential hazards, only SO_x, NO_x, and the particulates will be considered. Figures below show the relative amounts of pollutants in the U.S. released by fossil-fueled plants.

TABLE 7

Percent of Total Amount of Pollutants Released by Fossil-fueled Plants

Pollutant	Fuel Type Coal	Oil	Natural Gas	Percent Total
SO_x	42.7	3.3	-	46.0
NO_x	15.8	0.3	2.9	19.0
Particulates	10.5	0.1	-	10.6

Source: F.P.C. National Power Survey, 1970.

B. THERMAL POLLUTION

Thermal pollution is significantly different from other forms of pollution, since, unlike chemical wastes or sewage, it does not involve the addition of foreign matter to the environment and the heat is usually dissipated into the atmosphere rather quickly. The addition of heat to water bodies, however, may increase rates of chemical solubility and biochemical reactions, causing effects on aquatic organisms in the area of higher temperatures. All aquatic species have an optimum temperature range. If the water temperature varies above or below this range the chances of survival for

a particular species decrease. Rapid change in temperature caused by thermal plant start-up and shut-down can be lethal to organism in the effected area. Furthermore, an increase in the water temperature is always coupled with a decrease in ability of the water to hold oxygen, which is an adverse effect toward aquatic vertebrae.

A "safe" temperature has been defined by the Atomic Energy Commission as "the temperature which must persist as a mean temperature in order to protect whatever stage the organism is in". No definite average standards were given because they depend very much on local conditions, such as depth and speed of the stream, species living in it, etc.

The principal types of cooling system now in use or proposed for steam-electric plants are: a) once-through cooling using fresh or saline water, b) cooling ponds, including spray ponds, c) wet cooling towers, and d) dry cooling towers. In some cases a combination of systems may be used. The water withdrawal requirement varies widely among these systems, hence the choice between these techniques depends heavily on the availability of water, that is, its temperature, flow and speed.

The cost elements to be considered for thermal pollution control purposes are the capital costs and the operating costs. The Federal Power Commission gives the following estimates for the investment costs:

TABLE 8

Type of System	Investment costs $/KW (1970)	
	Fossil-fueled plants	Nuclear-fueled plants
Once-through	2.00 - 3.00	3.00 - 5.00
Cooling ponds	4.00 - 6.00	6.00 - 9.00
Wet Towers		
mechanical	6.00 - 8.00	8.00 - 11.00
natural	6.00 - 9.00	9.00 - 13.00

For dry towers, the F.P.C.'s estimates for investment costs range from $25 - $30 per kilowatt. Woodson in [5] has computed the following estimates of the differential production costs due to cooling for the different techniques in mills/KWH for a 800 MW plant and a load factor of 80% (1970):

TABLE 9

Technique	Fossil-fueled plants	Nuclear-fueled plants
Once through (ocean)	base	base
Once through (river)	0 mills/KWH	0.02 mills/KWH
Cooling lake	0.06	0.08
Mechanical wet tower	0.08	0.11
Natural wet tower	0.14	0.22
Mechanical dry tower	0.68	0.88
Natural dry tower	0.98	1.42

The following table is a result given us by S. Baron [5], based on F.P.C. findings in 1970, for 1000 MW plant with 80% load factor.

TABLE 10

Base Case, 1970 (1970 dollars; 1000 MW unit)

	Oil-fueled	Nuclear-fueled
Annual fixed charges on construction cost	3.6 mills/KWH	5.6 mills/KWH
Fuel cost	4.0	1.8
Maintenance, Operating, and insurance	0.2	0.4
Power generation cost	7.8 mills/KWH	7.8 mills/KWH

The comparison between different techniques shows that, from an economic point of view, even wet towers with natural draft do not add much to production costs. The difference is much greater for dry towers. The difference between fossil-fueled plants and nuclear plants arises from the greater amount of waste heat that must be dissipated for each kilowatt-hour produced. (Cooling efficiency in nuclear plants ~ 10% lower than in fossil-fueled plants.)

C. AIR POLLUTION

Although the electric utility industry consumes about one-fourth of all fuel burned in the United States, it contributes only about one-eighth of the total mass of pollutants

emitted into the Nation's air. Fossil-fueled power plants have, until very recently, accounted for almost one-half of the national total of sulfur oxide pollutant because of the extensive use of sulfur-containing fuels. Other significant pollutants, and the ones most difficult to control in the utility furnaces, are the oxides of nitrogen. Power plants account for about one-fifth of the national total. The particulates emitted from electric power plants, which are in most cases amenable to control, also account for about one-fifth of the national total. Figures below are estimates in 1960 given by the F.P.C.:

TABLE 11

Estimated Emission from Fossil-fueled Steam-Electric Power Plants in 1960

Source	Capacity (MW)	SO_x tons	SO_x % of U.S. total	NO_x tons	NO_x % of U.S. total	Particulate tons	Particulate % of U.S. total
Coal-fired	685	15.5	46.69	3.0	14.7	5.6	19.79
Oil-fired	104	1.3	3.91	0.4	1.94	0.02	0.07
Natural gas	304	-	-	0.6	2.91	-	-
Total	1,093	16.8	50.60	4.0	19.42	5.62	19.86

1. Sulfur Oxides

In most utility combustion processes approximately 90 to 95 percent of the sulfur in fossil fuels is oxidized

and enters the flue gas as sulfur dioxide (SO_2) and sulfur trioxide (SO_3), with about 97 percent of the SO_x being in the form of sulfur dioxide gas. Sulfur dioxide can be injurious to human and animal health and to vegetation. The small quantities of sulfur trioxide (SO_3) are emitted more in the form of an aerosol than as a gas. Sulfur trioxide is highly corrosive which effects the plant and the outside environment as well. Environmental standards for SO_x and NO_x are listed in the following table:

TABLE 12

Environmental Standards on Air Pollution

Type of Fuel	Pollutant	Concentration Standard	Discharges per year/MW	Yearly volume for dilution m^3/MW
Coal	SO_x	0.1 ppm	306×10^6 lbs	5.31×10^{11}
Oil	SO_x	0.1 ppm	116×10^3 lbs	2.02×10^{11}
	NO_x	2 ppm	47×10^3	5.77×10^9
Natural gas	SO_x	0.1 ppm	0.027×10^3	4.5×10^7
	NO_x	2 ppm	26.6×10^3	3.22×10^9

Note that figures in the last column of the above table are the yearly volume required for diluting the amounts released in order to meet the standards for different fuels in use.

Several possibilities are envisioned for SO_2 control, depending on the place where the control is made. Examples are:

- use of low sulphur fuel
- removal of sulphur from oil or coal prior to combustion
- removal of SO_2 from the stack gases.

Removal of sulphur from fuel prior to combustion is possible for oil and for natural gas, in fact, in the U.S. natural gas is usually delivered sulphur free. For coal a suitable process has yet to be found [13].

Several techniques are possible for removing SO_2 from stack gases. The processes envisioned to date as the most interesting economically, use dolonite, alkalized alumina, and catalytic oxidation. Other completely different solutions to the problem of SO_2 pollution include: production of electricity in places where the problem is less important; the use of nuclear power plants; and the use of hydro-electric power, the availability of which is very limited.

Cost estimates for SO_2 control vary widely, for example the Department of Interior, as quoted by Strauss [33], gives the following figures (prior to combustion control):

a. removal of sulphur from oil (reducing the sulphur content from 2.5% to 0.5%): \$2 to \$3 per ton or 8¢ to 12¢ per million BTU.

b. removal of sulphur from coal (reducing the sulphur content from 3% to 1.5%): 50¢ to 75¢ per ton or 2¢ to 3¢ per million BTU.

c. removal of SO_2 from the stack gases (90% of SO_2 removed): \$1 to \$2 per ton or 4¢ to 8¢ per million BTU.

These figures show that the process for removing sulphur from coal prior to combustion, although cheap, gives the fuel a content which is still too high to meet the standards in most of the cases. Costs of removing sulphur from stack gases are presently estimated, according to Strauss, to be \$0.75 to \$1 per ton and are expected to decrease in the future to the range of 20¢ to 25¢ per ton. The Battelle Memorial Institute, as quoted by Sylvan Denis [13], gives the following orders of magnitude for the two processes it has tested for a 800 MW plant burning 3% sulphur coal with a load factor of 80% (the coal cost is approximately 3 mills/KWH).

TABLE 13

Process	Capital Costs	Operating Costs	
	\$/KW	mills/KWH	\$/ton coal
Alkalized alumina	10.64	0.537	1.54
Catalytic oxidation	21.25	0.613	1.75

Since construction costs and operating costs for SO_2 control devices are themselves functions of plant size, Battelle found the following relationship:

$$\frac{(\text{capital cost})_i}{(\text{capital cost})_j} = \frac{\text{size plant}_i}{\text{size plant}_j}^{0.6}$$

And the formula for production cost is:

$$PC = \frac{CC \times K + AOC}{8760 \times LF \times 10^{-2} \times N}$$

where:

PC = production costs (\$/KWH)

CC = construction costs (\$)

K = annualization factor for non-recurring costs (mainly capital cost)

AOC = annual operating cost (\$)

LF = load factor

N = generating capacity (KW).

It is interesting to note that all figures given above do not include credits for sales of by-products, that is, sulphur and sulphuric acid. Bettelle has estimated that the quantity of sulphur, as the by-product of the combustion of coal burned in one year, is roughly equivalent to the quantity produced each year in the U.S. by conventional method. And as an example, a cost of 0.5 mills/KWH for sulphur removal is roughly equivalent to a cost of $45 per ton of sulphur not released in the atmosphere, and that is not much more than the present sulphur prices in the Northeastern area of the United States. Therefore, if the necessary technologies have been utilized, de-sulphurization process could be self sustaining in terms of costs and no charge will be added to the energy cost.

2. Nitrogen Oxides

The problem is rather different since the direct health effects of the nitrogen oxides are less well known. The main effect is photochemical smog, the formation of which involves sunlight and is not yet fully explained. Standards have been set but are likely to be lowered in the future as the knowledge of NO_x effects is improved.

There are several possible means of controlling power plant emissions of nitrogen oxides, basically they are: a) improving the combustion process, b) using oil or natural gas instead of coal, and c) removing NO_x from flue gas. It is difficult to achieve complete control of NO_x in power plants because of the interacting effects of pollutants. The conditions favorable to high NO_x production are a result of combustion practices to achieve better power plant operating efficiency and to control other pollutants. According to the F.P.C. [35], five major factors that can effect NO_x emissions are:

- the quantity of excess air for combustion, which must be minimum
- the pre-heat temperature, which must be minimum
- the heat release and removal rates
- the distribution and mixing of fuel and air
- the fuel type and its nitrogen content.

The most interesting techniques to reduce NO_x emissions are low-excess air fireing, two-stage combustion, flue gas

recirculation or a combination of these techniques. Another alternative is to remove NO_x from flue gases, which is also interesting since the oxides of nitrogen and sulphur can be removed at the same time. This is perhaps the reason why cost estimates for NO_x treatment from flue gases per se are not available. The only available cost estimate is that given us by Denis [13]; that is, for coal-fired plants the costs range from -0.02 mills/KWH to 0.36 mills/KWH, taking into account a credit for SO_2 removal and sale of by-products.

3. Particulates

Advances in automatic combustion controls have helped eliminate smoke nuisance from power plants, and the development of a variety of dust collectors has made it possible to control the fly ash problems. There are two general types of fly ash collecting equipment usually used in power plants: mechanical separators and electrostatic precipitators. Bag filters and wet scrubbers may also be used to remove particles and are in operation in some industrial establishments and a few power plants.

The costs of precipitators increase rapidly at the higher collection efficiencies. On the 500 - 800 MW plant, a precipitator of 95% efficiency may cost between $800 to $1,200 per MW; one of 99% efficiency may cost in excess of $2,500 per MW [FPC estimate]. Other cost estimates, such as operating and maintenance costs of these devices are not available. However, judging from the description of the processes currently in use, the operating and maintenance costs will not be significant.

As a summary of this section, if urban concentration obliges one to set very tight standards for SO_2 emissions (recall that NO_x removal can be done simultaneously with that of SO_x), and if water availability and climatic conditions are such as to oblige the utility to use natural draft dry cooling towers (which is the most expensive) in order to meet the thermal standards, the production cost of electricity (800 MW, 80% load factor) will increase, according to Denis [13], about 1.75 mills/KWH or according to Baron's estimate [5] about 1.7 mills/KWH more than if no control is done at all. These figures can then be taken as approximate upper bounds for pollution control.

VII. CONCLUSIONS AND AREAS FOR FURTHER STUDIES

A. CONCLUSIONS

It has been indicated in Section III that in order to ensure the stability of the service, the utility company is required to maintain at any time a reserve of capacity, which is commonly called the spinning reserve, as a safety margin above the actual demand. This requirement is met by running extra generators. As a result, an additional variable cost is incurred. However, only Bary [2] recognizes its existence explicitly as a separate element of the total annual variable costs. Theoretically, customers should not be held responsible for the spinning reserve cost, because it is neither a part of their demands nor an overhead. But, in reality, the reverse is true.

Consider a collection of large customers, presumably Government's installations, which operate under a budget constraints and at the same time seek to maximize their utility. To model various pricing policies which will be applied to them, consider the following notation:

- i = individual customer index
- j = period index, or time interval index which for the moment takes the values $j = 1,2$
- u^i = $u^i(x_1^i, x_2^i, y^i)$, individual's utility function
- x_j^i = the i^{th} individual's consumption of the utility service in period j.
- y^i = the i^{th} individual's consumption of the composite goods

b^i = the i^{th} individual's budget constraint

P^i_j = the price charge to the i^{th} individual for his consumption during period j; or equivalently, the price of commodity (i,j)

K = annual capacity cost for the use of the utility's fixed assets.

c^i_j = $c^i_j(x^i_j, K)$ is the variable cost of producing electricity during period j and consumed by the i^{th} individual

c^i_{sj} = $c^i_{sj}(x^i_{sj}, K)$ is the i^{th} individual's share of the spinning reserve in period j.

Assume that the amount of spinning reserve is approximately constant (i.e., the number of extra generators is constant), then $c^i_{sj} = c^i_s$.

The first pricing policy that will be considered is $P^i_j = P^i_j$, i = 1,2 and j = 1,2; that is we have (i x j) different commodities (a differentiation of customers and time of consumption). Each individual utility maximization can be portrayed as follows:

$$\max \quad z = u^i(x^i_1, x^i_2, y^i) \quad \ldots. \qquad (1)$$

s.t.

$$\sum_{j=1}^{2} P^i_j x^i_j + y^i = b^i$$

The Lagrangian of the above is

$$L = u^i(x^i_1, x^i_2, y^i) + \eta^i[b^i - \Sigma_j \, P^i_j x^i_j - y^i]$$

The first order conditions for the maximization problem are:

$$\frac{\partial L}{\partial x_j^i} = 0 = u_j^i - \eta^i P_j^i \quad ; \quad j = 1,2... \tag{2}$$

$$\frac{\partial L}{\partial y^i} = 0 = u_y^i - \eta^i \tag{3}$$

$$\frac{\partial L}{\partial \eta^i} = 0 = b^i - \Sigma_j P_j^i x_j^i - y^i \tag{4}$$

Summing (4) over i yields:

$$B - \Sigma_i \Sigma_j P_j^i x_j^i - Y = 0 \; ; \; B = \Sigma_i b^i \, , Y = \Sigma_i y^i \tag{5}$$

Upon differentiating (5) with respect to P_j^1 we get:

$$P_1^1 x_{11}^1 + x_1^1 + P_2^1 x_{21}^1 + Y_1^1 = 0$$

$$P_1^1 x_{12}^1 + x_2^1 + P_2^1 x_{22}^1 + Y_2^1 = 0$$

$$+$$

$$P_1^1(x_{11}^1 + x_{12}^1) + P_2^1(x_{21}^1 + x_{22}^1) + (Y_1^1 + Y_2^1) = 0 \tag{6}$$

And also differentiating (5) with respect to P_j^2 will get a similar result except for the superscript. In general, therefore, the result is

$$\sum_{\ell=1}^{2} P_\ell^i \sum_{j=1}^{2} (x_{\ell j}^i) + \sum_{j=1}^{2} Y_j^i = 0 \tag{7}$$

where

$$x_{\ell j}^i = \frac{\partial x_j^i}{\partial P_\ell^i} \quad \text{and} \quad y_j^i = \frac{\partial Y}{\partial P_j^i} \qquad i = 1,2$$

The Government is assumed to maximize social utility; i.e.,

$$\max Z = w(u^1,u^2) \tag{8}$$

s.t.

$$\sum_{i=1}^{2} \sum_{j=1}^{2} c_j^i + \sum_{i=1}^{2} c_s^i + K + Y = B$$

$$\sum_{i=1}^{2} \sum_{j=1}^{2} c_j^i + K = \sum_{i=1}^{2} \sum_{j=1}^{2} P_j^i x_j^i$$

The Lagrangian of (8) is

$$L = w(u^1,u^2) + \lambda[B - \Sigma_i\Sigma_j\ c_j^i - c_s - K - Y] +$$

$$\mu[\Sigma_i\Sigma_j\ P_j^i x_j^i - \Sigma_i\Sigma_j\ c_j^i - K] \tag{9}$$

where $c_s = \Sigma_i\ c_s^i$ is the total annual spinning reserve. The optimal size of the plant capacity can be found by differentiating (9) with respect to K which yields

$$-(\lambda+\mu)[\Sigma_i\Sigma_j\ c_{jK}^i + c_{sK} + 1] = 0 \tag{10}$$

where

$$c_{jK}^i = \frac{\partial c_j^i}{\partial K} \quad \text{and} \quad c_{sK}^i = \frac{\partial c_s^i}{\partial K}$$

The price of each commodity P_j^i can be found by differentiating (9) with respect to P_j^i, for all i and j:

$$\frac{\partial L}{\partial P_1^1} = w_1[u_1^1 x_{11}^1 + u_2^1 x_{21}^1 + u_y^1 y_1^1]$$

$$+ \lambda[-c_{11}^1 x_{11}^1 - c_{s1} x_{s1}^1 - y_1^1 - c_{21}^1 x_{21}^1]$$

$$+ \mu[P_1^1 x_{11}^1 + x_1^1 + P_2^1 x_{21}^1 - c_{11}^1 x_{11}^1 - c_{21}^1 x_{21}^1 - c_{s1} x_{x1}]$$

$$= 0$$

Substitute the results of equations (1) through (6) into the above yielding:

$$-w_1 \eta^1 x_1^1 + (\lambda+\mu)[(P_1^1 - c_{11}^1)x_{11}^1 + (P_2^1 - c_{21}^1 x_{21}^1]$$

$$+ (\lambda+\mu)x_1^1 - (\lambda+\mu)c_{s1} x_{s1}^1 = 0$$

or

$$(\lambda+\mu)[(P_1^1 - c_{11}^1)x_{11}^1 + (P_2^1 - c_{21}^1)x_{21}^1] - (\lambda+\mu)c_{s1}^1 x_{s1}^1 =$$

$$w_1 \eta^1 x_1^1 - (\lambda+\mu)x_1^1 \tag{11}$$

Similarly:

$$\frac{\partial L}{\partial P_2^1} = 0 = -w_1 \eta^1 x_2^1 + (\lambda+\mu)[(P_2^1 - c_{12}^1)x_{12}^1 + (P_2^1 - c_{22}^1)x_{22}^1]$$

$$+ (\lambda+\mu)x_2^1 - (\lambda+\mu)c_{s2}^1 x_{s2}^1$$

or,

$$(\lambda+\mu)[(P_2^1-c_{12}^1)x_{12}^1 + (P_2^1-c_{22}^1)x_{22}^1] - (\lambda+\mu)c_{s2}^1x_{s2}^1 =$$

$$w_1\eta^1x_2^1 - (\lambda+\mu)x_2^1 \qquad (12)$$

Summing up (11) and (12) we get

$$(\lambda+\mu)[(P_1^1-c_{11}^1)x_{11}^1 + (P_2^1-c_{21}^1)x_{21}^1 + (P_1^1-c_{12}^1)x_{12}^1 + (P_2^1-c_{22}^1)x_{22}^1]$$

$$- (\lambda+\mu)[c_{s1}^1x_{s1}^1+c_{s2}^1x_{s2}^1] = w_1\eta^1(x_1^1+x_2^1) - (\lambda+\mu)(x_1^1+x_2^1)$$

or in matrix form the formulation is

$$(\lambda+\mu)\begin{bmatrix} x_{11}^1 \\ x_{21}^1 \\ x_{12}^1 \\ x_{22}^1 \end{bmatrix}^T \begin{bmatrix} P_1^1-c_{11}^1 \\ P_2^1-c_{21}^1 \\ P_1^1-c_{12}^1 \\ P_2^1-c_{22}^1 \end{bmatrix} - (\lambda+\mu)\begin{bmatrix} c_{s1}^1 \\ c_{s2}^1 \end{bmatrix}^T \begin{bmatrix} x_{s1}^1 \\ x_{s2}^1 \end{bmatrix} =$$

$$= w_1\eta^1\Sigma_j x_j^1 - (\lambda+\mu)\Sigma_j x_j^1 \qquad j = 1,2 \qquad (13)$$

A similar result to that of (13) can be obtained if we differentiate (9) with respect to P_1^2 and P_2^2, and the result is

$$(\lambda+\mu)\begin{bmatrix} x_{11}^2 \\ x_{21}^2 \\ x_{12}^2 \\ x_{22}^2 \end{bmatrix}^T \begin{bmatrix} P_1^2-c_{11}^2 \\ P_2^2-c_{21}^2 \\ P_1^2-c_{12}^2 \\ P_2^2-c_{22}^2 \end{bmatrix} - (\lambda+\mu)\begin{bmatrix} c_{s1}^2 \\ c_{s2}^2 \end{bmatrix}^T \begin{bmatrix} x_{s1}^2 \\ x_{s2}^2 \end{bmatrix} =$$

$$= w_2 \eta^2 \Sigma_j x_j^2 - (\lambda+\mu)\Sigma_j x_j^2 \qquad \text{for } j = 1,2 \qquad (14)$$

The final formulation in a matrix form is the result of combining equations (13) and (14); that is:

$$(\lambda+\mu)\begin{bmatrix} x_{11}^1 & x_{21}^1 & x_{12}^1 & x_{22}^1 \\ x_{11}^2 & x_{21}^2 & x_{12}^2 & x_{22}^2 \end{bmatrix} \begin{bmatrix} (P_1^1-c_{11}^1) & (P_1^2-c_{11}^2) \\ (P_2^1-c_{21}^1) & (P_2^2-c_{21}^2) \\ (P_1^1-c_{12}^1) & (P_1^2-c_{12}^2) \\ (P_2^1-c_{22}^1) & (P_2^2-c_{22}^2) \end{bmatrix} -$$

$$-(\lambda+\mu)\begin{bmatrix} c_{s1}^1 & c_{s2}^1 \\ c_{s1}^2 & c_{s2}^2 \end{bmatrix} \begin{bmatrix} x_{s1}^1 & x_{s1}^2 \\ x_{s2}^1 & x_{s2}^2 \end{bmatrix} = \begin{bmatrix} w_1 \eta^1 \Sigma_j x_j^1 - (\lambda+\mu)\Sigma_j x_j^1 \\ w_2 \eta^2 \Sigma_j x_j^2 - (\lambda+\mu)\Sigma_j x_j^2 \end{bmatrix}$$

$$\text{where } j = 1,2 \qquad (15)$$

From (15) we can compute P_1^1, P_2^1, P_1^2 and P_2^2 which we know that each one of them will contain the share of each customer of the reserve cost. If we let $i = 1,2,\ldots,I$ and $j = 1,2,\ldots,J$, then we get the general formulation for this pricing policy, that is

$$(\lambda+\mu)'[\vec{D} \cdot \vec{P}] - (\lambda+\mu)[\vec{R} \cdot \vec{S}] = \vec{w} \qquad (16)$$

where

$$\vec{D} = \begin{bmatrix} x_{11}^1 & x_{21}^1 & \cdots & x_{J1}^1 & - - - & & & & x_{1J}^1 & x_{2J}^1 & \cdots & x_{JJ}^1 \\ & & \vdots & & x_{12}^2 & x_{22}^2 & \cdots & x_{J2}^2 & & & \vdots & \\ & & \vdots & & & & \ddots & & & & \vdots & \\ x_{11}^I & x_{21}^I & \cdots & x_{J1}^I & - - - & & & & x_{1J}^I & x_{2J}^I & \cdots & x_{JJ}^I \end{bmatrix}$$

$$\vec{P} = \begin{bmatrix} (P_1^1 - c_{11}^1) & & & (P_1^I - c_{11}^I) \\ \vdots & - - - & & \vdots \\ (P_J^1 - c_{J1}^1) & & & (P_J^I - c_{1J}^I) \\ \vdots & (P_1^2 - c_{12}^2) & & \vdots \\ \vdots & (P_2^2 - c_{22}^2) & & \vdots \\ \vdots & \vdots & \ddots & \vdots \\ \vdots & (P_J^2 - c_{J2}^2) & & \vdots \\ (P_1^1 - c_{1J}^1) & & \ddots & (P_1^I - c_{1J}^I) \\ \vdots & - - - & & \vdots \\ (P_1^1 - c_{JJ}^1) & & & (P_J^I - c_{JJ}^I) \end{bmatrix}$$

$$\vec{R} = \begin{bmatrix} c_{s1}^{1} & \cdots & c_{sJ}^{1} \\ \vdots & & \vdots \\ c_{s1}^{I} & \cdots & c_{sJ}^{I} \end{bmatrix}$$

$$\vec{S} = \begin{bmatrix} x_{s1}^{1} & \cdots & x_{s1}^{I} \\ \vdots & & \vdots \\ x_{sJ}^{1} & \cdots & x_{sJ}^{I} \end{bmatrix}$$

and

$$\vec{w} = \begin{bmatrix} w_1 \eta^1 \sum_{j=1}^{J} x_j^1 - (\lambda+\mu) \sum_{j=1}^{J} x_J^1 \\ \vdots \\ w_I \eta^I \sum_{j=1}^{J} x_j^I - (\lambda+\mu) \sum_{j=1}^{J} x_J^I \end{bmatrix}$$

Since the elements of $\vec{D}$ and $\vec{P}$ are itself matrices, then the appropriate thing to do is to define those element matrices. Let:

$$D_{k\ell} = [x_{1\ell}^{i} \quad x_{2\ell}^{i} \cdots\cdots x_{J\ell}^{i}] \qquad \begin{array}{l} i = 1,2,\ldots,I \\ k = 1,2,\ldots,I \\ \ell = 1,2,\ldots,J \end{array}$$

$$P_{i\ell} = \begin{bmatrix} P_1^i - c_{1\ell}^i \\ P_2^i - c_{2\ell}^i \\ \vdots \\ P_J^i - c_{J\ell}^i \end{bmatrix} \qquad \begin{array}{l} i = 1,2,\ldots,I \\ \ell = 1,2,\ldots,J \end{array}$$

Therefore, the general formulation given in (16) can be rewritten as:

$$(\lambda+\mu)\begin{bmatrix} D_{11} & \cdots & D_{1J} \\ \vdots & & \vdots \\ D_{I1} & \cdots & D_{IJ} \end{bmatrix}\begin{bmatrix} P_{11} & \cdots & P_{I1} \\ \vdots & & \vdots \\ P_{1J} & \cdots & P_{IJ} \end{bmatrix} -$$

$$- (\lambda+\mu)\begin{bmatrix} c^1_{s1} & \cdots & c^1_{sJ} \\ \vdots & & \vdots \\ c^I_{s1} & \cdots & c^I_{sJ} \end{bmatrix}\begin{bmatrix} x^1_{s1} & \cdots & x^I_{s1} \\ \vdots & & \vdots \\ x^1_{sJ} & \cdots & x^I_{sJ} \end{bmatrix} =$$

$$= \begin{bmatrix} w_1\eta^1 \sum_{j=1}^{J} x^1_j - (\lambda+\mu)\sum_{j=1}^{J} x^1_j \\ \vdots \\ w_I\eta^I \sum_{j=1}^{J} x^I_j - (\lambda+\mu)\sum_{j=1}^{J} x^I_j \end{bmatrix} \tag{17}$$

Notice here that the number of elements of each $D_{k\ell}$ denotes the number of time intervals (j) that we are interested in, while the number of elements in a row of the $\vec{D}$ matrix denotes the number of different tariffs that the utility has.

The second pricing policy is a simplification of the above, i.e., the utility differentiates only two time intervals in which one of them covers the peak period and the other covers the off peak period. The policy can be described as: $P^i_j = P^i_j$ where $j = 1,2$ and $i = 1,2,\ldots,I$. Equation (17) becomes:

$$(\lambda+\mu)\begin{bmatrix} D_{11} & D_{12} \\ \vdots & \vdots \\ D_{I1} & D_{I2} \end{bmatrix}\begin{bmatrix} P_{11} \cdots\cdots P_{I1} \\ P_{12} \cdots\cdots P_{I2} \end{bmatrix} - (\lambda+\mu)\begin{bmatrix} c^{1}_{s1} & c^{1}_{s2} \\ \vdots & \vdots \\ c^{I}_{s1} & c^{I}_{s2} \end{bmatrix}\begin{bmatrix} x^{1}_{s1} \cdots\cdots x^{I}_{s1} \\ x^{1}_{s2} \cdots\cdots x^{I}_{s2} \end{bmatrix}$$

$$= \begin{bmatrix} w_1 \eta^1 \sum_{j=1}^{2} x^1_j - (\lambda+\mu) \sum_{j=1}^{2} x^1_j \\ \vdots \\ w_I \eta^I \sum_{j=1}^{2} x^I_j - (\lambda+\mu) \sum_{j=1}^{2} x^I_j \end{bmatrix} \qquad (18)$$

where each $D_{k\ell}$ and $P_{i\ell}$ has 2 elements.

The last pricing policy that will be considered is, perhaps, the most simple from a practical point of view; that is, $P^i_j = P_j$ for all i ($j = 1,2,\ldots,J$). In this policy, all customers are confronted with the same commodity in each time interval. Thus the utility's revenue can be formulated as:

$$\sum_{i=1}^{I} \sum_{j=1}^{J} P^i_j x^i_j = \sum_{j=1}^{J} P^i_j \left(\sum_{i=1}^{I} x^i_j \right)$$

$$= \sum_{j=1}^{J} P_j X_j \qquad \text{where } X_j = \Sigma_j \, x^i_j \quad .$$

The Lagrangian of the individual customer's utility maximization is:

$$\max L + \mu^i(x^i_1,\ldots,x^i_J,y^i) + \eta^i[b^i - \Sigma_j P_j x^i_j - y^i] \qquad (19)$$

where $j = 1,2,\ldots,J$. Results of the first order conditions of (19) will be similar to that of equations (2) through (4) and the steps necessary from there on are the same, except, now we have $\Sigma_i x_j^i = X_j$.

The resource allocation problem facing the economy can be written as:

$$\max L = w(u^1,\ldots,u^I) + \lambda[B-\Sigma_j c_j - c_s - K - Y] + \mu[\Sigma_j P_j X_j - \Sigma_j c_j - K] \tag{20}$$

where: c_j = the variable cost of producing electricity during period j consumed by all customers, that is, $c_j = c_j(X_j,K)$

$c_s = \Sigma_j c_{sj} = c_s(X_s,K)$ is the variable reserve cost.

Consequently, the optimal plant size is given by differentiating (19) with respect to K, which yields

$$-(\lambda+\mu)[\Sigma_j c_{jK} + c_s + 1] = 0 \quad ; \quad j = 1,2,\ldots,J \tag{21}$$

The first order conditions are:

$$\frac{\partial L}{\partial P_j} = \Sigma_i w_i[\Sigma_\ell u_\ell^i x_{\ell j}^i + u_y^i y_\ell^i] + \lambda[-\Sigma_\ell c_{\ell\ell} X_{\ell j} - c_{ss} X_j - Y_j]$$

$$+ \mu[X_j + \Sigma_\ell P_\ell X_{\ell j} - \Sigma_\ell c_{\ell\ell} X_{\ell j} - c_{ss} X_{sj}] = 0$$

$$\text{where} \quad \begin{aligned} j &= 1,2,\ldots,J \\ \ell &= 1,2,\ldots,J \\ i &= 1,2,\ldots,I \end{aligned}$$

Making the appropriate values of u^i, y^i, and Y_j to the above we get:

$$-\Sigma_i w_i \eta^i x_j^i + (\lambda+\mu)[X_j + \Sigma_\ell (P_\ell - c_{\ell\ell}) X_{\ell j}] - c_{ss} X_{sj} = 0 \quad (22)$$

Therefore, the general formulation of this pricing policy is,

$$(\lambda+\mu) \begin{bmatrix} X_{11} & \cdots & X_{J1} \\ \vdots & & \vdots \\ X_{1J} & \cdots & X_{JJ} \end{bmatrix} \begin{bmatrix} P_1 - c_{11} \\ \vdots \\ P_J - c_{JJ} \end{bmatrix} - (\lambda+\mu)\, c_{ss} \begin{bmatrix} X_{s1} \\ \vdots \\ X_{sJ} \end{bmatrix} =$$

$$\begin{bmatrix} \sum_{i=1}^{I} w_i \eta^i x_1^i - (\lambda+\mu) X_1 \\ \vdots \\ \sum_{i=1}^{I} w_i \eta^i x_J^i - (\lambda+\mu) X_J \end{bmatrix} \quad (23)$$

From both equations (18) and (23) we can conclude that the inclusion of capacity charges in the energy bill can be justified on the ground that it represents the reserve cost incurred at any point in time.

B. AREAS FOR FURTHER STUDIES

We saw in Section V that there are three methods of allocating capacity costs among customers: i.e., peak responsiblity method, non-coincident peak and average-and-excess demand method. The first method can well be

portrayed through a pricing policy $P_j^i = P_j$ for all i, in which equation (23) is the result of such policy. The second is well reflected by equation (18) where $P_j^i = P_j^i$ for all i and j. The third method, however, has received little attention and provides an area for an interesting study. The method was introduced by Caywood [12] and its formulations were based upon empirical technical studies. Therefore it needs an economic justification

The next area which will provide an interesting study is the elasticity of demand for electricity by large customers, should the Government decide to increase the price of electricity as a result of a full crisis. This study should be able to determine the optimal range of price increases within which consumption will not be seriously affected.

APPENDIX A

GLOSSARY OF COMMON TERMS

Capacity	- the load for which a machine, apparatus, station or system is rated
Capacity factor	- the ratio of average load on a machine or equipment for the period of time considered to the rating of the machine or equipment
Coincidence factor	- the reciprocal of diversity factor
Coincident demand	- any demand that occur simultaneously with any other demand; also the sum of any set of coincident demands
Demand factor	- the ratio of the maximum demand of a system, or part of a system, to the total connected load of the system, or part of the system under consideration
Diversity factor	- the ratio of the sum of the non-coincident maximum demands of the various subdivisions of a system, or part of a system, to the maximum demand of the whole system, or part under consideration
Load diversity	- the difference between the peak of coincident and non-coincident demands of two or more individual loads
Load factor	- the ratio of the average load over a designated period to the peak load occurring in that period
Non-coincident demand	- the sum of the individual maximum demands regardless of time of occurrence within a specified period, usually not more than one year
Diversified maximum demand of a class	- the product of the individual maximum demand of the class and an appropriate interclass coincidence factor

Peak day	-	the day within a stated period of time in which the maximum demand occurs
Peak demand	-	the greatest of a particular type of demand occurring within a specified period (= maximum demand)
Peak responsibility	-	the load of a customer, a group of customers, or part of a system at the time of occurrence of the system peak.

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This paper is a study of the current state of the art, in both the theory and actual practice, of electricity pricing in the United States under capacity and revenue constraints. It is also an attempt to derive an efficient pricing policy that will be applied to large Government installations. A mathematical formulation of electricity pricing using two different approaches is presented.

(20. ABSTRACT continued)

Components of the total cost of service are examined along with various methods of allocating them among classes of customers. Also discussed are difficulties in allocating capacity costs due to the existence of joint costs. Commonly used methods of allocating capacity costs are presented along with a discussion of the merits of each. Finally, this paper explores the impact of electricity generation upon the environment, especially thermal and air pollution, and methods of controlling each type of pollution in the context of overall pricing are discussed.

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